Injection Returns and Evolution of Non-Condensible Gases at the NCPA Geysers Wellfield, California

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ABSTRACT

NCPA is the developer and operator of the second-largest power installation at The Geysers steam field in California, generating some 120 MW at the southern end of the reservoir using 68 production wells and 8 injection wells. The current total monthly steam production is about 1.451 million lbs, and about 90% of this is replaced annually by a re-injection stream that comprises about 2,000 gpm of combined (treated) sewage and lake water and about 1,600 gpm of combined condensate and rain runoff. Routine monitoring of the stable isotopes and steam chemistry of production is carried out to evaluate injection returns (injection-derived steam), and the first comprehensive evaluation of the returns and evolution of non-condensible gases in the reservoir and production since 2001 has now been completed. In contrast to experience further north in the reservoir, the weighted average total gas / steam concentration of the NCPA wellfield has remained stable since about 1991, at about 3,000 ppm-wt. H_2S has also remained stable at 100~150 ppm-wt. The dome-shaped reservoir has a well-defined halo of gas / steam that increases towards the top and sides, and the general character of this halo has not been changed by injection. NCPA gases are different in composition from a previously defined Southeast Geysers type, with high levels of total C and N, and high CH_4 / CO_2 (molar value up to 3) found especially in the far south. These gases are either released by local sedimentary rocks, or they are a remnant of the early Geysers reservoir, before it was once flushed by meteoric water.

Introduction

Established in 1968, the Northern California Power Agency (NCPA) is a California Joint Action Agency. NCPA membership is open to municipalities, rural electric cooperatives, irrigation districts and other publicly owned entities interested in the purchase, aggregation, scheduling and management of electrical energy. NCPA operates two geothermal power plants of 110 megawatts each at The Geysers geothermal field, located in the Mayacamas mountains of Sonoma and Lake Counties, and the agency also owns and operates the 70 deep production wells that supply these power plants with steam. The geothermal project also includes 8 deep injection wells used to re-supply the geothermal reservoir with water to create additional steam, 10 miles of surface pipelines to deliver the produced steam to the plants, two surface water collection ponds, and a co-owned major wastewater delivery system consisting of five pump stations and 26 miles of underground pipeline that are used to supply additional fluids for injection. In December 2008, a 1 MW, 30% capacity factor solar photovoltaic project was commissioned at one of the effluent pumping stations whereby a renewable project (solar) is used to support another renewable project (geothermal), all the while disposing of treated wastewater for the nearby communities of Lake County.

The NCPA portion of The Geysers steam field occupies an area of about 6.5 square km at the southern extremis of the reservoir, which in its entirety is about 20 km long and 5 km wide. Steam production and injection of condensed steam back into the NCPA area started in January 1983, but at that time the area was still being developed and was under different ownership. NCPA purchased the project in October 1985, when there were 15 production wells and 4 wells that had been used for injection. Field development continued, and the last of the "original" wells in the field was on-line by 1991. Since that time, 60 to 70 production wells have been on-line at any one time, and two wells have been added, one drilled in 2003 and another in 2005. Over 20 different wells have now been used for injection at some time or another, but of these only a few have been used for injection only and never produced. Only one well, the centrally located A-1, has been used for injection almost continuously since 1985, and by 2007 this well had received four times as much injection as any other single well.

As in other parts of The Geysers steam field, the original practice of injecting condensate back into the reservoir, along with small amounts of surface water, was able to replenish only

20~30% of the mass of steam produced. The result of this, combined with a lack of natural recharge, was a steep decline of reservoir pressure. Field operators responded by seeking external sources of water for injection. The first of these to be established was the Southeast Geysers Effluent Project (SEGEP), referred to above, which delivers secondary-treated wastewater from Lake County to injection wells of the NCPA well field and a portion of the Calpine well field just to the north. SEGEP commenced operations in late September 1997, and since that time some NCPA injection wells have received SEGEP water only, others have received a mix of SEGEP water and condensate, and one continues to receive (small amounts of) condensate only. Annual SEGEP deliveries to NCPA were about a billion gallons until 2003 and increased thereafter to about 1.7 billion gallons in 2007 (somewhat lower in 2008). Annual condensate injection was about a 0.8 gallons during 2001-3, and declined slightly to about 0.75 billion gallons in 2007.

A second project that delivers (tertiary-treated) wastewater from the City of Santa Rosa began to supply injection wells of the central and northern Geysers field in November 2003. NCPA does not participate in the Santa Rosa project and none of the Santa Rosa water is injected close enough to the NCPA field to directly affect its operations.

In spite of the enhanced injection, most of the NCPA wells produce steam that is superheated at the wellhead, by about 10° to 30°C. An exception is many wells at pads E- and J- at the southeastern corner of the reservoir, where NCG are particularly high and there is evidence of formation water along the boundary of the reservoir.

As a routine part of field management, NCPA once a year collects samples of the steam at each production well for analysis of the concentration and composition of non-condensible gases (NCG) in the steam, and for analysis of stable isotope deuterium (D or ^{2}H) in the steam condensate. The NCG are of interest because total concentration affects power plant efficiency and the hydrogen sulfide (H_2S) component must be stripped out to prevent atmospheric pollution. Deuterium is of interest because NCPA cycles its steam condensate through cooling towers, where evaporation causes a large shift of D in the residual condensate that is then injected, by comparison with original steam produced. When this D-shifted water re-appears at production wells (as so-called Injection-Derived Steam, or IDS), its presence can be detected and the fraction condensate IDS calculated (more below).

NCPA routinely monitors the new NCG and isotope data that are obtained each year, and periodically carries out a comprehensive evaluation of the entire gas and isotope database with respect to long-term trends and developments, and reservoir processes (*e.g.* GeothermEx, 1988; GeothermEx, 1991; Klein and Enedy, 1989; Truesdell and others, 1993; Truesdell and others, 2001). This report describes selected results from the most recent evaluation, for which the cut-off date has been samples collected in 2007. For a discussion of the earliest conditions in the wellfield (*c.*1983~87) the reader is referred to the sources listed above. The emphasis herein is on conditions and changes since 1988. Excellent discussions of geologic setting, the natural creation of the steam reservoir and its evolution over geologic time, its NCG content and gas composition and stable isotopes across the entire Geysers reservoir (but with scant attention to the NCPA area) have been provided by various studies cited herein, including Lowenstern and others (1999) and Beall and others (2007).

The NCPA steam chemistry database now comprises more than three thousand stable isotope analyses and over sixteen hundred NCG analyses. To process and evaluate these data, the two sources were merged using database software and correlated with steam production data using a look-up routine that assigned to each piece of chemical information the steam flow rate and wellhead pressure at the time of sample collection. The final assembled database (in MS-Access) could then be queried to extract information for automated graphing and to calculate trends and weighted averages in the well field as a whole, and among geographic sub-sets of the wells (usually divided among the twelve well pads that are distributed more-or-less evenly across the area). The automated graphing was used to produce on two pages a detailed history of each separate production well, including (a) time graphs for flow rate, wellhead pressure, stable isotopes, volume percent dry gas composition (CO_2, H_2S, NH_3, N_2, Ar, CH_4 and H_2)), ppm-wt NCG, ppm-wt H_2S, and the lb/hr rates of NCG, H_2S, total Carbon and total Nitrogen; (b) the simultaneous injection histories of 19 different wells (to cross-check for injection-production interferences) and; (c) several different correlation diagrams, some of which are discussed below.

As a convention herein, NCG refers to total non-condensible gases in steam, expressed as parts per million by weight (ppm-wt) or as moles per thousand moles of H_2O, whereas gases or gas composition refers to the composition of the NCG as volume percent (v%) of the dry gas, or as moles gas/moles H_2O.

Injection Returns

Table 1 illustrates estimates of field-wide total IDS production that are based on deuterium measurements in 1988, 1997 and 2007 (the data for 1997 represent pre-SEGEP conditions scaled to the entire year). These estimates represent a simple two-component mixing model (condensate and "native" reservoir steam) applied to each well separately, followed by determining a weighted average according to flow rate. The estimates are approximate. Although each well has been assigned its own "base" level of "native" δ-D (typically in the range -50 ‰ to -55 ‰ and most often close to the lower value), it is assumed (except for 2007) that this does not change over time. It is assumed that injected condensate boils completely, so that there is no shift of deuterium when IDS forms. It has been assumed that D in average injected condensate has not varied over time, yet some variation must have occurred. (The average δ-D is -11.5 ‰ but most measurements date from the early 1990s.) Finally, the possible effects of injection to the north of NCPA are not considered. These various restrictions do not seriously compromise the estimates for 1988 and 1997, because mixing involved only two primary components.

In contrast, the estimate for 2007 is quite uncertain, because the two-component mixing model is trying to handle a three-component situation. The third component is SEGEP injection, but the deuterium composition of SEGEP water has not been documented in detail. Of two samples collected one resembles "native" NCPA reservoir steam (δ-D about -55 ‰) and the other resembles a modest mix (-42 ‰) between original steam and condensate IDS. The calculations for year 2007 in Table 1 illustrate this uncertainty by showing the range of results for two different assumptions. In the first case (numbers to the left), it is assumed that SEGEP has no effect on the reservoir steam component because most SEGEP water has a deuterium level close to -55 ‰, *i.e*. the calculation is equivalent to those for 1988 and 1997. The second case (numbers to the right) represents an adjustment of the first case that assumes a shift of field-wide average reservoir steam (before mixing with condensate) from δ-D -55 ‰ to -50 ‰, as a result of mixing with SEGEP fluid. Both cases assume that SEGEP IDS is recovered at the same rate as condensate IDS. The two cases span a wide range of results. With the first assumption the increased injection with SEGEP has added to total recovery of injectate (indeed, to the point that nearly all production is IDS). With the second assumption a decline of injected fluid recovery is estimated and 28% of production (the difference between 18,270,000 klb and 13,070,000 lkb) is still the "native" steam. A numerical simulation model of the reservoir, which is maintained for NCPA by GeothermEx, indicates that an additional increase of injection beyond the present level should result in a decrease of the present steam production/pressure decline rate. This suggests that the first year 2007 assumption in Table 1 is somewhat closer to being accurate than the second.

Figure 1 shows the distribution of condensate IDS at production wells in 2007, assuming that δ-D in the reservoir mixing fraction has not changed (equivalent to the first case of Table 1). SEGEP IDS is not included. The well receiving 31% of injection is used for SEGEP only, whereas the well receiving 27% of injection is used for a condensate-SEGEP mix.

Table 1. Total production and injection in 1988, 1997 and 2007, with estimated IDS produced (see text).

		1988	1997	2007
Total Injected - klb				
	Condensate	8,020,000	7,313,000	6,450,000
	SEGEP			14,450,000
	TOTAL	8,020,000	7,313,000	20,900,000
Total Produced (metered) - klb		23,310,000	21,830,000	18,270,000
Fraction condensate IDS in production		0.06	0.25	0.31~ 0.22 (a)
Fraction condensate returned		0.17	0.75	0.88 ~ 0.63
Total Produced IDS - klb				
	From condensate	1,400,000	5,460,000	5,670,000 ~ 4,030,000
	From SEGEP (b)			12,690,000 ~ 9,040,000
	TOTAL IDS	1,400,000	5,460,000	18,360,000 ~ 13,070,000

(a) Ranges represent the results obtained using two different cases of reservoir steam δ-D. Values on the left use the assumptions of 1988 and 1997. Values on the right assume δ-D -50 ‰ (see text).

(b) SEGEP IDS is assumed to be recovered at the same fractional rate of return as condensate IDS.

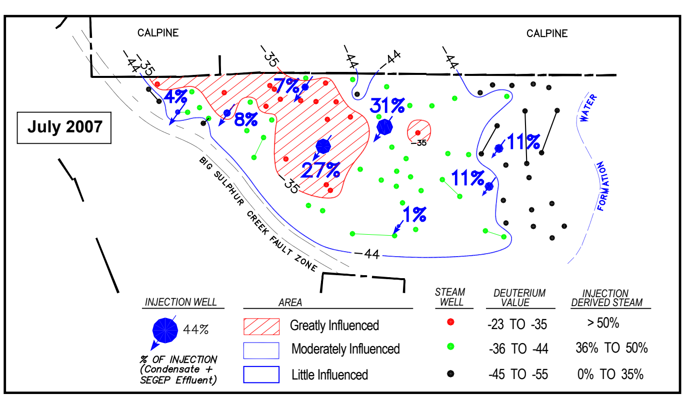

Figure 1. NCPA steam field, areas influenced by condensate injection in July 2007.

NCG Trends Over Time and In Space

Beall and others (2007) have shown that weighted average NCG in the wellfield that lies immediately north of NCPA and also gets SEGEP water (but not Santa Rosa water) has increased over time. Units 13/16 NCG was about 750 ppm-wt in 1988. It rose progressively to 1700 ppm-wt in July 1997, was stable for about 5 years following SEGEP onset, then rose progressively from 1700 to 2250 ppm-wt during 2003-2006. There is a well-defined power curve that correlates the increasing NCG with decreasing steam rate. When NCG rate (lb/hr) is plotted against steam rate, there is a well-defined pattern of increasing NCG flow until 1997, decreasing NCG flow from 1998 until about 2002, and increasing NCG flow since that time.

NCG in the NCPA area has behaved differently (Figure 2). There was an increase from 1000 ppm-wt in 1986 to 3000 ppm-wt in 1990, but nearly stable conditions and no net change since that time. NCG rate has also been almost completely stable since at least 1990 and perhaps before. When plotted against steam rate, NCG concentration generally increases as rate decreases, but the correlation is so weak (nothing like in Units 13/16) that it is not reproduced herein. Also not illustrated here is a graph of NCG rate against steam rate, which is essentially flat. In the NCPA field as a whole there was no clear response of NCG concentration or rate to SEGEP. H_2S in weighted average NCPA steam has been even more stable than NCG, never departing from the range 100 to 150 ppm-wt since 1986.

Within subdivisions of the NCPA field the picture is somewhat different, showing a variety of patterns locally that involve either stable, increasing or decreasing NCG concentrations and rates over time (Figures 3 – 5, overleaf, on which data point locations represent the average or dominant steam zones of the individual wells).

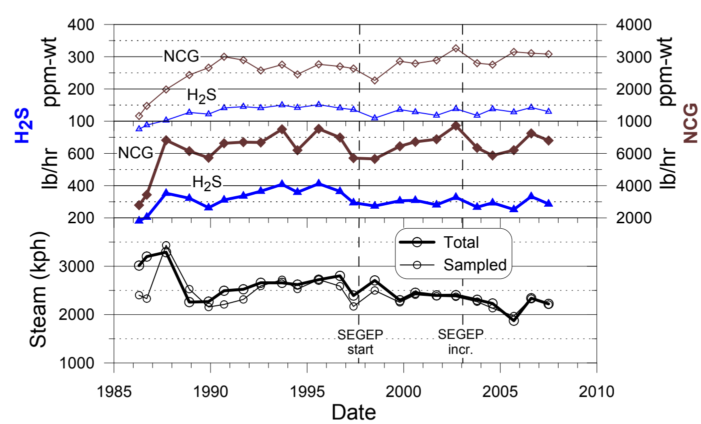

Figure 2. NCPA yearly steam rates, NCG concentrations and NCG flow rates. The curves for NCG concentration and flow rate are weighted averages of all wells sampled.

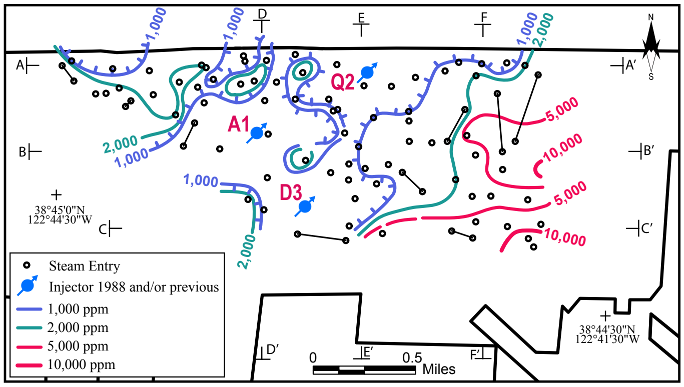

Figure 3. NCPA steam field, plan view of NCG concentrations in 1988. A broad zone of depressed NCG crosses the field from SW to NE, associated with previous injection into wells A-1 and Q-2 in particular. NCG increase somewhat to the NW, but particularly to the SE, where the production wells are deeper than elsewhere and produce the highest NCG levels.

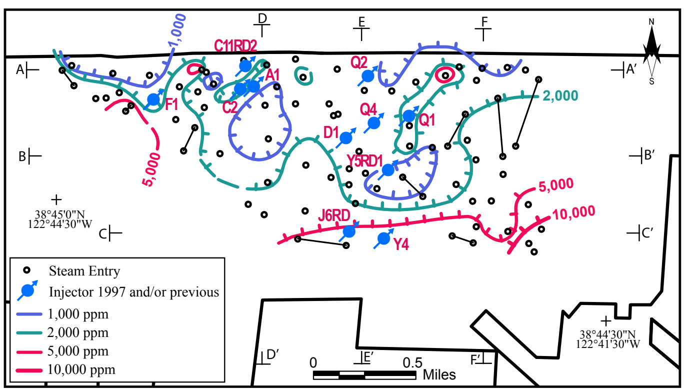

Figure 4. NCPA steam field, plan view of NCG concentrations in 1997.

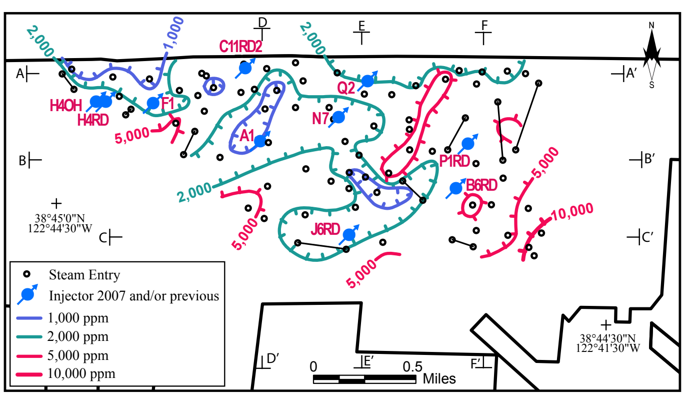

Figure 5. NCPA steam field, plan view of NCG concentrations in 2007. The general pattern of 1988 persists but is complicated by much of the injection having been dispersed in space and over time among (by now) 18 different wells. Only well A-1 has been used (almost) without stop. Of particular note is a "ridge" of elevated NCG that trends NE, located about half a kilometer east of the center of the field.

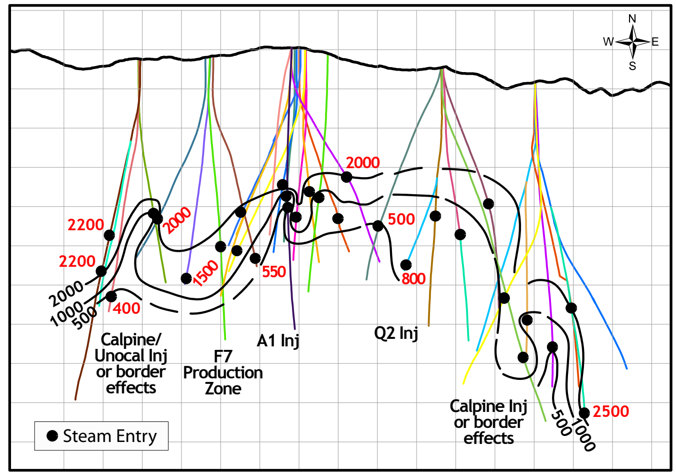

Figure 6. NCPA steam field, cross-section A-A′, NCG in 1988.

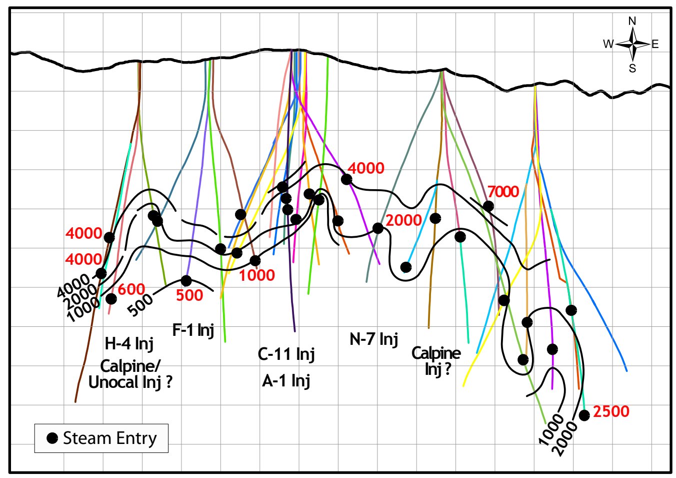

Figure 7. NCPA steam field, cross-section A-A′, NCG in 2007.

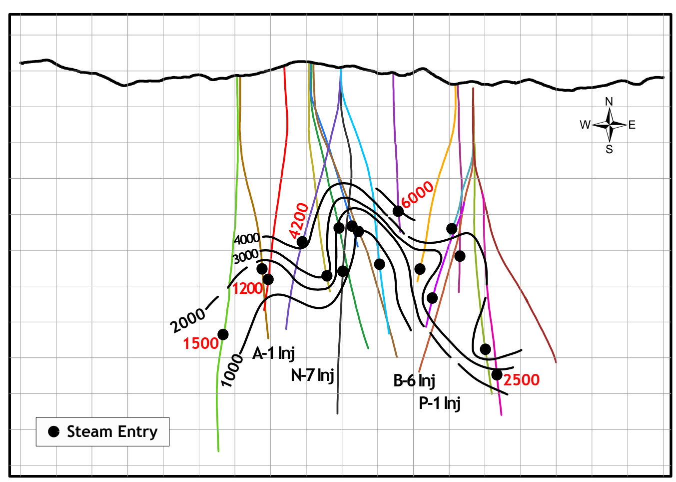

Figure 8. NCPA steam field, cross-section B-B′, NCG in 2007.

Cross-sections of the wellfield with NCG plotted at the average or dominant steam zone clearly show a halo of increasing concentrations moving upwards and outwards. Figures 6-8 show three cases, but others have been developed and the pattern is seen almost everywhere in the field, with local exceptions most of which are explained by variations outside the plane of the section, especially near the field margins. Increasing NCG towards the top of the reservoir further north in the Geysers were described by Truesdell and others (1993b) and most-recently have been discussed by Powell (2007).

The general halo pattern has persisted over time (at least since 1988), in spite of all varieties of patterns at individual wells, increasing, decreasing, stable, relatively unstable, and changing from one pattern to another. One extreme is a well (Q-6) that has maintained a strong flow under the influence of injection at the adjacent Q-2 (used for mixed condensate – SEGEP injection). From 1990 to 1998 the NCG at Q-6 remained stable at 1,000 ppm-wt even as δ-D increased from -50 to -30 ‰. In 1999 the NCG at Q-6 jumped to nearly 5,000 ppm-wt, and it maintained a similar high level until 2002, when it returned to 1,000. The probable explanation for the anomalous NCG during 1999-2001 is that increased injection (SEGEP came-on line) caused a temporal collapse of the local steam zone.

The NCG halo probably has developed as a result of several simultaneous processes. Natural steam circulation and Rayleigh condensation along the domed "roof" of the reservoir lead to a concentration of NCG along upper and outer margins (*e.g.* D`Amore and Truesdell, 1979). Steam production has boiled off the liquid water in these outer zones, leading to production of matrix fluids that contain the higher gases and a resulting increase of NCG (*e.g.* Lowenstern and others, 1999). Simultaneously, at deeper levels in the core of the dome, injected condensate and SEGEP water produce a very low NCG IDS that dilutes the NCG. This dilution must be occurring, but in detail the NCG and deuterium at a given well or cluster of wells usually show a weak correlation at best, and often none at all. Finally, it is probable that some of the high NCG comes from the reservoir cap rock (*e.g.* Powell, 2007). It is especially likely that the cap rock is a source of increasing NCG over time in the Units 13/16 area, and the NCG that must be entering the NCPA reservoir to maintain overall a stable NCG concentration in spite of massive injection.

Gas Composition

Just as changes of NCG at individual NCPA wells have varied widely yet the total field average has been nearly stable, the gas chemistry at many wells has varied considerably yet certain broad trends are evident. A common temporal disturbance comprises high levels of NH_3 (to >60 v%) that are associated with condensate IDS (Klein and Enedy, 1989; Beall, 1993) and tend to decrease when condensate IDS decreases. Also fairly common have been large temporal shifts of N_2/Ar, from levels of 200~600 (molar) that are characteristic of the native steam (Lowenstern and others, 1999), to about 80 which is characteristic of air and even to about 40 which is characteristic of air-saturated water. These also are associated with IDS, either because the injected water is air-saturated and/or because some injection wells tend to entrain air itself. A third temporal disturbance is anomalously high H_2, which can appear particularly at wells with low NCG. The source of these H_2 anomalies is uncertain, because H_2 is generally considered to be created by the thermal reduction of H_2O, which is temperature dependent and rapid to equilibrate. Anomalous behavior of H_2 has been reported from elsewhere in the Geysers (McCartney and Haizlip, 1989), but the cause of it has remained ambiguous.

When gas samples that are less disturbed are considered, the NCPA gases tend to be different from what has been described as Northwest, Central, Unit 15 and Southeast Geysers gas types by Lowenstern and others (1999). The difference between NCPA gases and the Southeast type is due in part to relationships between water/gas ratio and gas composition, the Southeast area (Units 13/16 and somewhat further north) having lower NCG overall than the NCPA area. The Southeast type has ~45 v% CO_2, about 15 v% H_2S, 25 v% H_2, and 5 v% each of CH_4, N_2, and NH_3. In the Southeast, Central and Northwest Geysers it is generally found that v% CH_4 correlates positively with CO_2 and N_2. In contrast, NCPA gases tend to have (a) higher levels of total C, total N, CH_4 and N_2, and (b) (except at the lowest CO_2 and CH_4 levels) there is a strong negative correlation between CH_4 and CO_2 (Figure 9). CO_2 and CH_4 together typically comprise about 50 to 80 v% of the NCPA dry gas, the sum being highest when CH_4 is highest. The wells with highest CH_4 and N_2 (and lowest CO_2) are all located in the southernmost-central part of the NCPA field, which suggests that there is a source of these two components in that area, perhaps organic matter in Franciscan sedimentary rocks. Alternatively, these gases may be a remnant of original Geysers gases that remained trapped at the southern tip of the reservoir when the reservoir was flushed out by an infiltration of meteoric water that occurred sometime in the past (this model of reservoir evolution has been explained, for example, by Beall and others, 2007 and by Lowenstern and others, 1999). Remnant gas highly enriched in C is still found deep in the far northwest Geysers, but in that area the ratio CH_4 / CO_2 is very low, not very high.

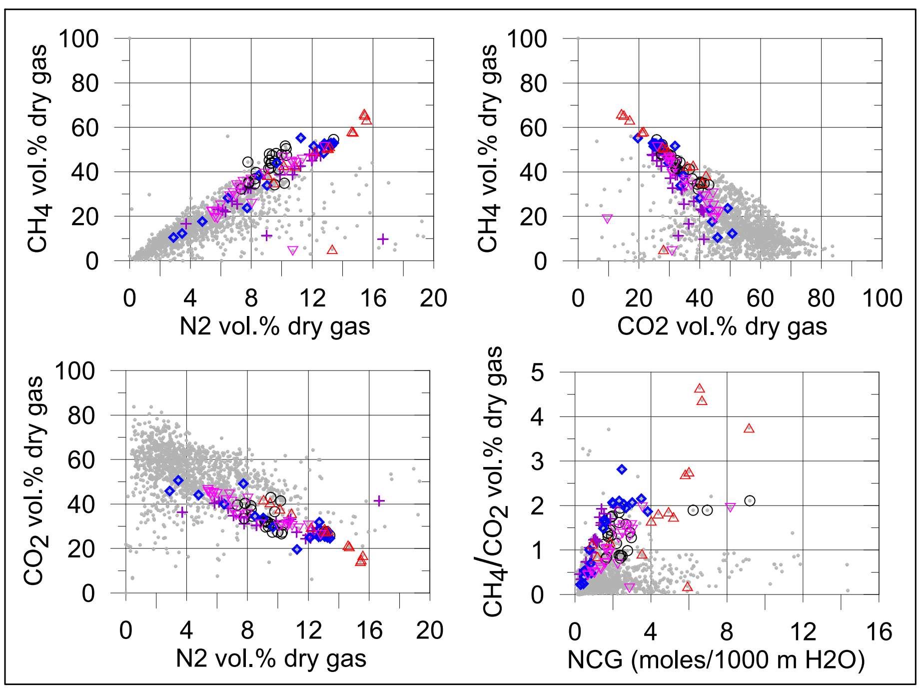

Figure 9. Correlations between CH_4, CO_2, N_2 and gas/steam in NCPA steam samples. Background grey dots represent all NCPA data, whereas the larger colored symbols represent five wells (A-3, D-2, D-6, J-5, Y-2) all located at the southern end of the central part of the wellfield.

Another approach to geothermal steam compositions is provided by plotting data on D`Amore gas geothermometer grids. A grid of this type shows how the chemical composition of a steam sample (expressed as moles gas / moles H_2O) can be related theoretically to (a) the temperature "t" of simultaneous equilibrium between two different chemical reactions and (b) factor "y," which represents the fraction of the steam that has come from equilibrium in a reservoir liquid phase versus the fraction coming from a reservoir steam phase. If y = 0, then all of the sample has come from boiling of reservoir liquid and if y = 1 the sample represents pre-existing reservoir steam. The type of D`Amore grid that is most-often applied to Geysers samples relates the reaction by which CH_4 and H_2O combine to produce CO_2 and H_2 (represented as "FT") to the reaction by which H_2 and H_2O combine with rock mineral pyrite (FeS_2) to form H_2S and the mineral magnetite (represented as "HSH"). There are numerous assumptions that underlie the construction, application and validity of these grids, which are well explained by Truesdell and others (2001). In terms of the equilibrium reactions themselves (in pure steam or pure water), an increase of temperature tends to produce CO_2 from CH_4 and to produce H_2S from H_2.

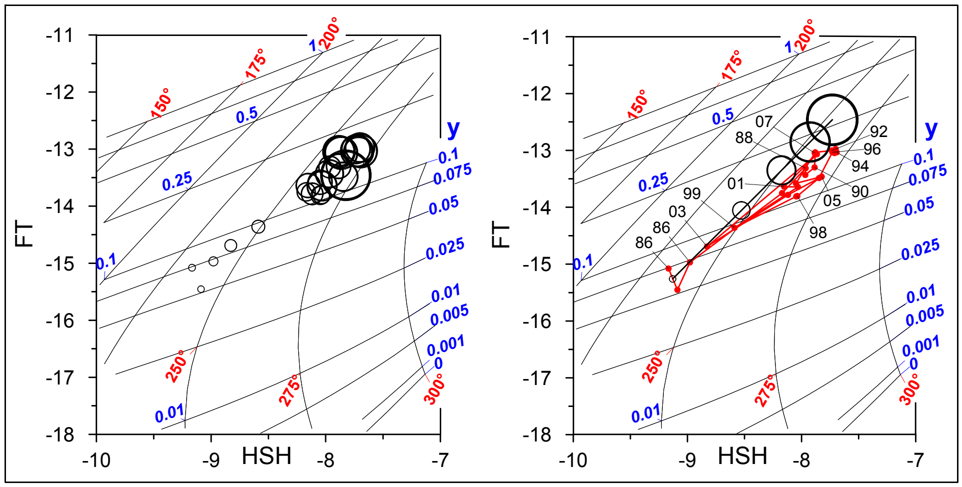

Figure 10. FT-HSH geothermometer-steam fraction grid (D`Amore grid) for well E-4, showing actual data in relation to a simple model of increasing NCG.

Truesdell and others (2001) have described how the historical samples from a single NCPA well tend to fall into one of four general patterns on a FT-HSH grid: linear, hairpin, cluster and random. (In addition, some wells shift between patterns over time, and some NCPA wells have shifted since first described by Truesdell and others, 2001.)

Data points in a linear pattern trend to progressively higher y values and usually higher t, which suggest processes of drying (progressive liquid boil-off) and heating. Hairpin patterns are similar, but the data reach a maximum y value and then shift back along the linear trend, and sometimes back and forth. This suggests partial re-watering of the steam source caused by injection, with adjustment of the chemical equilibria during the process. Cluster patterns are a group within relatively narrow confines of y and t that does not change over time. Some (indeed many) patterns start linear and end in a cluster, or have a temporal cluster during the well's history. In any case the cluster represents stable conditions under which injection has been effective, neither allowing reservoir volumes to dry out or water out. Random patterns (often extremely scattered) are a result of large departures from chemical equilibrium conditions and are often seen at particularly low gas concentrations (as along the northern edge of the NCPA wellfield) and during periods when a well has elevated NH_3 from condensate injection.

It is useful to illustrate the degree to which a linear or hairpin pattern is caused simply by a change of the total gas/steam ratio (*i.e.* change of NCG) without any change of the gas composition itself. Figure 10 shows the data from hairpin well E-4 along with a simple condensation model. On the left side the data are plotted as bubbles with diameters proportional to ppm-wt NCG. The range of NCG at E-4 has been 1,800 to 8,900 ppm-wt, increasing at first progressively, later leveling off and then swinging between extremes. The right side graph of Figure 9 shows (a) the actual data from well E-04 plotted as small filled circles, with year of sample collection, and (b) bubble points that illustrate a simple model of the effect of increasing NCG at constant dry gas composition. The model starts at the average gas composition and ppm-wt in the first two samples (year 1986), and progresses to higher and higher NCG across the range actually observed at the well.

The difference on Figure 10 between the simple model (higher slope) and the actual data (lower slope) is explained by small shifts of dry gas composition that did occur during the history of the well. Most dominantly, CH4/CO2 increased slightly (from about 0.17 to 0.2), causing a -0.2 shift of FT, and there was a tendency for H_2S/H_2O to increase slightly. Whether these shifts were caused by an actual increase of temperature (as the grid suggests) is uncertain.

Figure 10 therefore suggests that the "drying and heating" of a linear or hairpin pattern is mostly a matter of drying (liquid boil-off) and actual heating is much less certain. Boil-off would be a cooling process driven by heat in the boiling liquid and adjacent rock, and the rock that is near the boiling zone should be at the same starting temperature. Therefore, the only source of "heating" would be steam and/or gas that comes from hotter rocks deeper in the reservoir, in a "high temperature zone" such as exists beneath the northernmost part of The Geysers, or beneath the steam zone of the southern Geysers. E-4 is in the southeastern border zone of deep wells and so could be getting "hotter" gases from below. There are several other deep, border zone wells that also exhibit the linear and/or hairpin pattern, but the pattern extends to intermediate and shallow wells such as C-4, C-5, F-7, H-3, P-1 and Q-7, and some of these are on the upper periphery of the NCG halo that is described above. Therefore, they are not likely to produce gases that come from a significantly hotter zone beneath.

We suspect instead that the "heating" implied by linear and hairpin distributions on the FT-HSH grids is an artifact of NCG concentration shifts and small disequilibria which might include addition of CH_4 from an external source into the gas mixture (as

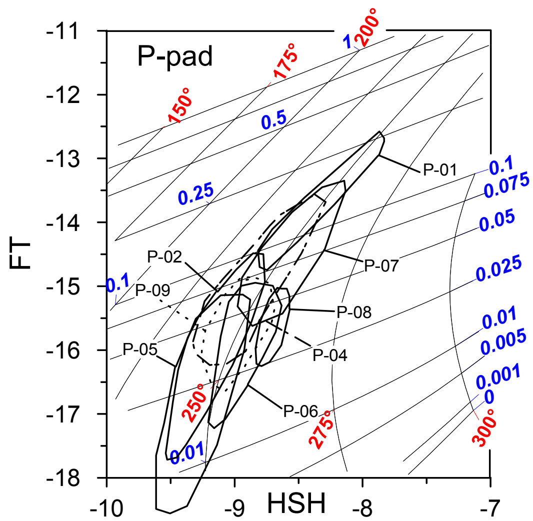

Figure 11. FT-HSH geothermometer-steam fraction grid (D`Amore grid) for the wells at pad P in the northeast corner of the NCPA field. The data field for each well surrounds those samples deemed to be "least disturbed" by anomalies such as high NH_3 that are associated with injection of condensate. These tend to have low H_2, which displaces data points towards higher HSH at lower FT. Anomalously high H_2 (also avoided) displaces data points towards lower HSH at higher FT.

suggested above). In contrast to the pattern of well E-4 (Figure 9), which slices rather strongly across the isotherms of the FT-HSH grid, there are wells and clusters of wells that tend more strongly to stay isothermal in terms of the grid (Figure 11). This suggests a better adjustment to chemical equilibrium conditions.

Conclusions

With the advent of SEGEP injection into the reservoir it is no longer possible to evaluate returns of IDS using deuterium analysis without a large uncertainty in the estimate, because two-component mixing has been replaced by three-component mixing and (in addition) the isotope composition of the SEGEP component has not been well-constrained. Rough estimates suggest nevertheless that return fractions are very high.

In contrast to experience further north in the reservoir, the weighted average total gas / steam concentration of the NCPA wellfield has remained stable since about 1991, at about 3,000 ppm-wt. H_2S has also remained stable at 100~150 ppm-wt. The dome-shaped reservoir has a well-defined halo of gas / steam that increases towards the top and sides, and the general character of this halo has not been changed by injection. NCPA gases are different in composition from a previously defined Southeast Geysers type, with high levels of total C and N, and high CH_4 / CO_2 (molar value up to 3) found especially in the far south. These gases are either released by local sedimentary rocks, or they are a remnant of the early Geysers reservoir, before it was once flushed by meteoric water.

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