1. INTRODUCTION

The Six Lakes Storage Field experienced an annual deliverability decline of 5.6% after full development was completed in the late 1960s. February peak withdrawal rates decreased from a high of 568 MMcf/d in 1968 to 284 MMcf/d in 1980. Deliverability was partially restored to 344 MMcf/d in 1981 with the drilling of 30 infill vertical wells. Deliverability continued to decline, and in 1992, the February peak day was reduced to 182 MMcf/d. A number of different avenues to evaluate and correct this problem were pursued in the 1990s. The best course of action to reverse the decline and restore deliverability was determined to be replacement of the aged vertical wells with state-of-the-art single- and dual-lateral horizontal wells. The drilling of 24 horizontal wells since 1994, along with the plugging of 200 (70%) of the vertical facility wells, has increased the February 2005 peak day deliverability to 250 MMcf/d.

2. FIELD HISTORY AND GEOLOGY

Six Lakes is located in west-central Michigan, USA and serves Michigan Consolidated Gas Company’s 1.2 million customers with a normal annual working capacity of 40 Bcf. The field provides a high degree of flexibility to the transmission system, as only one hour is required to change between injection and withdrawal. Since first employed for storage in 1953, over 3.0 Tcf has been cycled to and from the field.

The Six Lakes Stray Sandstone reservoir was discovered on May 11, 1934 and production began in September 1935. The field was developed on 40-acre spacing, and, by March 1936, there were 75 producing gas wells. Eventually, 224 producing wells, drilled by numerous companies, delineated the field. Field production totaled 51.5 Bcf by March 1953, with 53.3 Bcf total gas in place. The 64 remaining wells had wellhead pressures averaging 25 psig. The start of conversion to storage began with the injection of base gas in March 1953. Full development took a number of years and was completed in 1967. With delta pressure, the field has a total capacity of 68.6 Bcf.

Geologically the field is a sandstone reservoir of Late Mississippian age. The gas storage reservoir is the Stray Sandstone, part of the Michigan formation. Regionally, the Michigan Stray Sandstone is located between 1,200 and 1,300 feet below the surface and consists of a structural trap of porous and permeable sandstone. The sandstone is predominantly clean, well sorted and composed of gray to reddish colored quartz sand between 40 and 100 feet in thickness. Structurally the field consists of three parallel offshore barrier bars that trend from the northwest to the southeast. Overlying the Stray is the caprock, the National City formation. The National City is composed primarily of impermeable anhydrite. Underlying the Stray is the Marshal Formation, a fair to well cemented quartz sandstone that is gray in color with occasional reddish staining.

3. VERTICAL WELL PERFORMANCE

A study by Maurer1, completed in 1993, summarized the nationwide storage deliverability history of a number of North American operators. Maurer’s study mirrored the findings of MichCon in that field deliverability was declining at an annual rate of 5 to 6% as the historical decline rate at Six Lakes, with all vertical wells, was 5.6% per year. In 1968, the field delivered 568 MMcf/d on a February peak day. By 1980, under the exact same field and flowing pressures of 300 psig field pressure and a 70 psi drawdown, the delivery capability was reduced to 284 MMcf/d. Thirty infill vertical wells were drilled and the capability temporarily increased to 344 MMcf/d. It began to decline the following year until reaching a low of 182 MMCF/d in 1992. The all-vertical well field decline history through 1992 is shown below:
Although infill drilling of 30 vertical wells proved to be successful, it provided a temporary reprieve to deliverability decline.

The equation for either of the above lines is:

\[ Q_j = Q_i \times (1 - D)^{j-i} \]

For example, in 1968 the field flow was 568 MMcf/d. The calculated flow in 1980, with a 5.6% annual decline, would be:

\[ Q_{1980} = Q_{1968} \times (1 - 0.056)^{1980-1968} \]
\[ Q_{1980} = 568 \text{ MMcf/d x (0.944)}^{12} \]
\[ Q_{1980} = 568 \text{ MMcf/d x (0.5008)} \]
\[ Q_{1980} = 284.5 \text{ MMcf/d} \]

An analysis of individual well deliverability indicated that some degree of decline was occurring in all of the wells:
The above results were taken from individual well back-pressure tests run periodically in the past on each well and normalized to a common pressure-squared value. Our markets were reduced by 40% in the early 1980s during an economic recession. Budgets were severely restrained and limited back-pressure testing occurred after 1980. Grouping of data points in the late 1970s indicates increased testing frequency due to monitoring various stimulation attempts during that period. The above graph also shows that the then state-of-art stimulation methods (acid and/or solvent washes) performed on wells SL 23 and SL 183 in the mid to late 1970s were not effective and the program was discontinued.

Only two other methods have proven cost-effective. The first involves stimulating vertical wells with a simple coiled-tubing conveyed high-pressure water-jet wash. This method was successfully developed in the 1990s and removes the salt scale (referred to in flow test analysis as ‘skin’) that builds on the openhole face of the wellbore during withdrawal. Results for three years are shown below:

![Six Lakes Historical Information](image)

Although this method proved effective in restoring deliverability, it is a temporary solution. After treatment the vertical wells continued to decline at the average annual rate of 5.6% per year (not illustrated here but measured on individual well differential tests). The second method is discussed in the next section.
4. OVERALL FIELD RESULTS WITH HORIZONTAL WELLS

Field results through 2005 are as follows:

Figure 4

Six Lakes

At the start of the rejuvenation program in 1993, 240 MMcf/d was chosen as the target deliverability rate. This rate is less than that achieved in 1968 due to a number of high-deliverability fields being developed after 1968 and the market reduction which never fully recovered. Both the new fields and the market reduction lessened MichCon’s dependence on large end-of-season withdrawals from Six Lakes.

Separate agendas were simultaneously pursued for vertical well stimulation (after sidewall cores determined the major deliverability degradation component was salt scale), propellant stimulation (in conjunction with the Department of Energy), openhole perforations and losses due to the carryover of compressor station lube oils. In the late-1990s, these methods and their associated costs were evaluated and the simple water-wash stimulation proved to be the only non-horizontal well drilling option that consistently increased deliverability. The vertical well water-wash stimulation program’s shortfall was that the improved well deliverability was short-lived. Deliverability on the stimulated vertical wells began its typical decline shortly after stimulation. The first alternative, with a goal to increase deliverability to the target rate and then maintain that level of performance, would have been to stimulate 10% of the wells on an ongoing annual basis.

Concurrently during this timeframe a horizontal well was drilled to determine its behavior and compare it with forecast results. Based on its initial success additional horizontal wells, both single- and dual-lateral, were subsequently simulated, drilled and evaluated. Toward the end of this period, the long-term viability of the gathering system was evaluated. Its age, condition and non-piggable sections would have required replacement in its entirety. By converting the field to an all-horizontal well field, the older gathering lines could be removed and new, piggable pipe installed. The new pipeline would be fifteen miles in length as compared to the in-place forty five miles of gathering line required to reach all of the vertical wells. The reduction in pipeline length was not only due to fewer wells, but also attributable to placing the horizontal wells on strategically located well pads consisting of up to five wells per pad. An economic evaluation indicated that the all-horizontal well strategy (including plugging of most of the 288 vertical facility wells) was the better of the two alternatives (stimulate vertical wells and rebuild the gathering lines versus all horizontal wells and new gathering lines). Additional benefits of the all-horizontal system have been reductions in operating and maintenance expenses.
5. HORIZONTAL WELL ANALYSIS AND PERFORMANCE

After the drilling of the first horizontal well of 1,000 feet of openhole length, the theoretical capability of longer horizontal wells versus a typical vertical well was determined through simulation using PanSystem©. The results are shown here:

Figure 5

Vertical vs. Horizontal Well Theoretical Performance

Under bottomhole conditions the theoretical capability of a 5,000-foot horizontal well is eight times that of a vertical well. In practice, one must also account for other factors such as 1) higher frictional losses through the production casing, 2) not all wells may be drilled to 5,000 feet in length, 3) variations in vertical and horizontal permeability, net porosity, pay thickness and proximity to no-flow boundaries, and, 4) interference. The average vertical well delivered 0.63 MMcf/d on the February 1992 peak day. The average horizontal well delivered 8.85 MMcf/d on the February 2005 peak day. The ratio of 8.85 to 0.63 indicates that the one horizontal well is equivalent to fourteen 1992-vintage vertical wells. This higher-than-theoretical ratio is due in good part to the deteriorated deliverability condition of the 1992 vertical wells.

Other calculations were also made with the assumption of a skin damage factor of 10 for both types of wells. With the vertical well, a deliverability loss of 38% was calculated. With the horizontal well, a deliverability loss of 7% was calculated. The calculated decline of the simulated vertical well is consistent with the field-measured results. Actual results with the horizontal wells indicate that they decline at a much slower rate as no decline has yet been measured on the oldest horizontal wells:

Table 1

Six Lakes Horizontal Well Test Results – TAG-427

An effective openhole foot is defined as the length of well bore actively contributing flow during the test period. The only change noted in the above table is the drainage area which is a function of the test pressure, time period and in the later years, removal of nearby vertical wells.
The impacts of varying lengths of the horizontal sections were also simulated. As shown below, a well drilled with a horizontal section of 5,000 feet is theoretically 44% more productive than a well length of 2,500 feet:

**Figure 6**

5,000 foot vs. 2,500 foot Horizontal Well Theoretical Performance
44% Deliverability Increase

In order to determine if the theoretical calculations on the well bore length were on target, a single-leg well was re-entered and a second lateral was drilled. The results show that not only did the deliverability increase by 67%, but also so did the drainage area:

**Figure 7**

Six Lakes 2002
TAG-429 Second Lateral Drilling Results
In 2003, five horizontal wells that had some form of damage or restricted flow capacity were stimulated using a fresh water wash via coiled tubing. Two wells with high skin values were selected as were three wells with under-utilized lengths of the drilled openhole. The results were:

**Figure 8**

**Six Lakes 2003 Stimulation Results**

The above test results indicate the increase in deliverability after the stimulation work was completed. The best results were obtained in the horizontal wells that the analysis of test data indicated only a portion of the drilled openhole was contributing to flow on withdrawal. As discussed earlier in the theoretical calculations and as shown by actual field test results, skin damage does not significantly impact flow in horizontal wells. Effective length is of utmost importance, both in theory and in practice.

The replacement of vertical wells with horizontal wells has significantly increased the amount of openhole exposed for gas flow:

**Figure 9**

**Six Lakes Openhole Footage**

The footage of openhole in the vertical wells has decreased from 11,200 feet in 1994 to 3,240 feet in 2005 as vertical wells were plugged or otherwise removed from facility well service. The
horizontal openhole footage has climbed to 92,820 feet during that period with an average openhole length 3,710 feet. The drainage area of the wells is shown below, normalized to acres per 1,000 feet of effective feet of openhole:

![Figure 10](image)

Test periods range from 300 to 400 hours with hourly flowrate, temperature and pressure data measured and analyzed. The drainage area is affected by the quality of the storage formation permeability and proximity to vertical facility wells. All the above drainage areas were from calculated from test data taken during the first three weeks of withdrawal in December 2004. Analysis of data from late-season periods indicates that the drainage area increases by factors of up to four as the well's distance of influence increases with time.

6. CHALLENGES

Two major challenges remain: well cleanup and brine production. After the completion of the drilling operation cuttings can clog the wellbore. Cleanup during the drilling operations and subsequent withdrawal periods has not been very effective on some of the longer-reach wells drilled in the early 2000s:

![Figure 11](image)
Modifications to the cleanup procedure used at the conclusion of drilling have been made to reduce the likelihood of leaving cuttings or other obstructions in the openhole section. Secondly, analysis needs to be completed to determine why a few horizontal wells produce formation brine and what steps need to be taken on the existing wells, and eliminated on future wells, to reduce the influx of brine during withdrawal.

7. CONCLUSION

Horizontal wells are a feasible and economical alternative in the maintenance of deliverability in storage fields. After up to ten years of service, they have not demonstrated any skin damage or age-related deterioration in deliverability performance.

ACKNOWLEDGEMENTS

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NOMENCLATURE

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Definition</th>
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<tr>
<td>Bcf</td>
<td>1,000,000,000 standard cubic feet, ft³</td>
</tr>
<tr>
<td>d</td>
<td>day</td>
</tr>
<tr>
<td>D</td>
<td>annual deterioration decline expressed as a decimal</td>
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<tr>
<td>Mcf</td>
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<tr>
<td>MMcf</td>
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<td>psig</td>
<td>pounds per square inch gauge</td>
</tr>
<tr>
<td>Tcf</td>
<td>1,000,000,000,000 standard cubic feet, ft³</td>
</tr>
<tr>
<td>i</td>
<td>initial year, i.e. 1968</td>
</tr>
<tr>
<td>j</td>
<td>future or final year, i.e. 1980</td>
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SUBSCRIPTS

Figure 12
Typical Pad Location View for Horizontal Wells