SMALL WELL-HEAD COMPRESSOR FOR FIELD GAS COMPRESSION

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ABSTRACT

Current increase in drilling activity of existing fields and re-entry in oil fields brought on by upgrading of gas and oil pricing structures has necessitated small well-head compression. Types, size limitations, configurations, design features and operations are discussed for compressors available in size ranges from 10 horsepower to 200 horsepower. Today's field design and application requirements for maximum compression flexibility and minimum compressor horsepower are discussed.

For each oil and gas producer large or small, the small well-head compressor (Figure 1) is his answer to more oil production and dollars available now from natural gas. Portability of each compressor package eliminates the need for high-cost low-pressure gas gathering lines required in single compressor-station location. As a well's gas volumes declines, a small compressor package can be moved to the next location with minimum hook-up cost or returned to the lessor if the package has been rented.

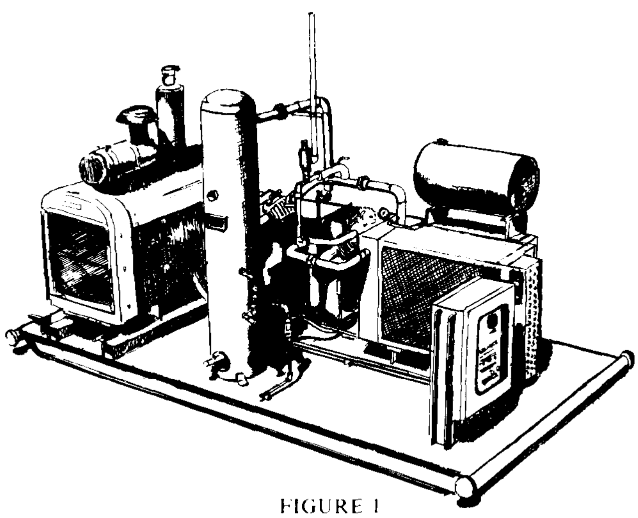

FIGURE 1

Each producer's requirements are different, depending on well population and sales line pressure. In this paper, a small well-head compressor will be defined at 10-200 horsepower. By use of Table 1 volumes can be derived for the available horsepower and pressure ranges.

TABLE 1

DISCHARGE PRESSURE PSIG.

ESTIMATED BHP TO COMPRESS NATURAL GAS PER MMSCFD

THREE STAGE / TWO STAGE / SINGLE STAGE

SUCTION PRESSURE PSIG.	25	50	75	100	150	200	350	500	600	750	800	900	1000	1250	1500	1750	2000
0	65	100	130	145	170	190	235	250	260	275	280	290	300	315	330	345	350
10	35	65	85	105	130	145	185	215	230	235	240	250	255	275	290	300	310
25		40	55	70	95	120	150	175	185	205	210	220	230	240	255	265	275
50			25	40	70	80	120	140	155	170	175	180	190	205	215	230	245
75				20	45	55	95	120	130	145	150	155	165	180	195	205	215
100					30	45	75	100	115	130	135	140	145	160	170	180	195
150						20	55	75	85	105	110	115	120	135	150	160	165
200							40	60	70	80	85	95	100	115	125	140	150
250							25	45	55	65	70	80	85	105	115	125	135
300							20	35	45	55	60	70	75	80	85	100	120
350								25	35	50	55	60	65	75	90	100	110
400								20	30	40	45	50	55	70	80	90	105
450								15	20	30	35	40	50	60	70	80	100
500									15	30	35	40	45	55	60	75	95
550									15	25	30	35	40	50	55	70	90
600										20	25	30	35	45	55	65	85
750											15	20	25	35	40	55	75
1000														20	30	40	50
1250															25	30	40
1500																20	30
1750																	20

Once the horsepower requirements have been established, the heart of the compressor package is the proper selection of compatible engines and compressors. Compressor frame ratings are established on the basis of speed and maximum input horsepower. The optimum engine selection will provide sufficient horsepower to load the compressor at its rated speed. Due to the limited number of engines available, it may be necessary to operate an engine by reducing speed to match a compressor frame rating. For example, an engine rated at 100 horsepower at 1400 RPM can provide, through the use of belt drive, a full 100 horsepower to the compressor. However, this same engine may be required to provide only 80 horsepower to a direct driven compressor rated at only 1000 RPM.

Gas Compressors (meaning frame, cylinder or cylinders, and drive component) are available in many varieties. The most acceptable description without using manufactures names is as follows.

1. Integral (Engine — compressor in same frame) heavy duty water cooled, slow speed.
2. Belted units — heavy duty — slow speed pressure lubricated.
3. Belted units — air cooled splash lubricated, slow to medium speed.
4. Balanced opposed heavy duty — water cooled high speed, pressure lubricated.
5. Balanced opposed — air cooled splash lubricated, up to 1800 RPM.
6. Belted unit-medium speed — air cooled, single acting cylinders, splash or pressure lubricated.

Each compressor variety has multiple cylinder sizes to provide maximum flexibility in obtaining the correctly sized compressor package for the producer's needs. Compressor cylinders are available in double-acting, single-acting, combination double- and single-acting (two-stage), and step-cylinder (single-acting two-stage) configurations. Compressors are limited in design as are engines. The compressor stroke will usually determine the speed and horsepower limitations of the gas compressor being considered for the application.

The small well-head compressor package will normally consist of all or some of the following components in addition to the engine and compressor.

1. Oilfield type skid (2 or 3 runner full-depth members)
2. Suction and interstage scrubbers complete with automatic dump valves, high level shutdown devices, and sight glass gauges.
3. Control panel complete with all necessary engine and compressor shutdown indications.
4. Aerial type cooling for engine and compressor jacket water, and gas aftercooling.
5. Oil make-up systems for engine and compressor.
6. Start-up bypass piping.
7. Necessary guards and protective devices to meet personnel safety requirements.

Ease of installation, operation, and maintenance is considered in the design of a compressor package. Since well-head compression needs to be a minimal expense to the producer, installation of a unit will be designed for suction and discharge gas connections and either no foundation or a port-a-block type mounting. Compressor packages are designed so that minimum maintenance such as oil and spark plug changes and minor compressor valve upkeep are all that will be required. However, everyone knows that mechanical equipment will require additional attention at one time or another. That is why proper location of each component on the package helps eliminate unnecessary time spent to repair or remove an item for maintenance.

It should be pointed out that proper compressor operation is highly dependent upon satisfactory operation of field production equipment upstream of the unit.

Production requirements are generally about the same for all producers. Pipeline pressures on sales lines or contract pressures vary, as do expected operating pressures of the wells. A project design requires operating pressures, gas volumes, and gas composition to size the most efficient system. There are two options available to establish a gathering system requiring compression. One is to provide multiple units, each compressing from a single well. The other is to provide a single large unit gathering from multiple wells. In evaluating which approach to take, gathering equipment availability, system flexibility, cost, and system efficiency must be considered. In general, the best compressor efficiency, the most flexibility, and considerable cost savings in piping can be achieved with the multiple unit approach.

Misstated flow volumes for new wells is probably the most common item for oversizing of compressors and cause of inefficient operations. Open flow test reports of a new well will be used for design of the compressor, and after the well has been produced for a short period of time a reduction of about one-quarter to properly apply a gas compressor should be based on as much history about the reservoir as possible. Also each producer's rate of depletion would be based on reservoir data and government regulations.

For an application of the small well-head compressor, let us consider the criteria mentioned above and introduce some additional guidelines or shortcuts to find the compression needs. A proven reservoir has been producing oil and gas at a separator pressure of 75 psig with the gas flowing into an existing gathering system. Because the existing gathering system has become overloaded or a new sales line with higher gas purchase prices has been installed near the separator location, a compressor may look feasible. The new sales line pressure is operating at 350 psig with a contract pressure of 500 psig. At the 75 psig separator pressure, the normal flowing volume has been 400 mscfd. But, the reservoir engineer tells us that addition volumes could be produced if the separator pressure was lowered to 25 psig.

Using Table 1 and taking 75 psig suction pressure and 350 psig discharge pressure the BHP/mmscfd is 95, requiring a single stage compressor. Using 400 mscfd as our volume, the required horsepower would be 38 BHP. (Rule of thumb is BHP=Ratio of compression x 22BHP/mscfd x mmscfd x number of stages. Ratio of compression (R_c) to be limited to 5.0 per stage).

$$R_c = \frac{\text{Discharge Pressure (psia)}}{\text{Suction Pressure (psia)}}$$

However, a 25 psig suction pressure would produce a 600 mscfd and would require two stages of compression for a total of 90 BHP. With the two-stage compressor, the contract pressure of 500 psig can be reached with a small reduction in capacity. Cylinder sizing would be determined by the maximum volume at the lowest suction pressure.

The incremental volume increase of 200 mscfd at a gas price of $2.00/mcf would result in a payout of less than 1 year on a cost of $60,000 for a 100 horsepower two-stage compressor. Should an investor group be involved and a rental program be determined to be the best approach, a $12,000/month income would easily cover the $2100/month rental rate, and a maintenance and operation contract of approximately $600 to $700 per month.

As the reservoir depletes, the volume reduction causes the suction to drop below 25 psig. However, the separator must operate a 25 psig to be efficient. The small well-head compressor must again be flexible. To help maintain the 25 psig separator pressure, the compressor capacity can be controlled by reducing the speed, adding clearance to the compressor cylinder, unloading one end of a double-acting cylinder, or by automatic bypass control.

Should the capacity of the well maintain a higher flow than expected, the cylinder size selected for the 25 psig suction pressure may now overload the engine at higher suction pressure. The higher suction pressure would result from the compressor package's inability to clear the hump shown in the curve in Figure 2.

Clearance is again used for maintaining the efficiency of the compressor and providing the needed flexibility. The curve also shows the critical period of operation of a small well-head compressor. This period is when the well is first put on stream after a shutdown and the well has "headed" up. Most of the time an engine can stand a slight overload during this period, but sometimes the suction block valve to the compressor must be used as a throttle valve to reduce the suction pressure and create the higher ratio, lower volume effect. To provide proper selection for a user of any gas compressor package, most packages are equipped with computer programs and capabilities for drawing curves representative of units available.

TYPICAL CURVE

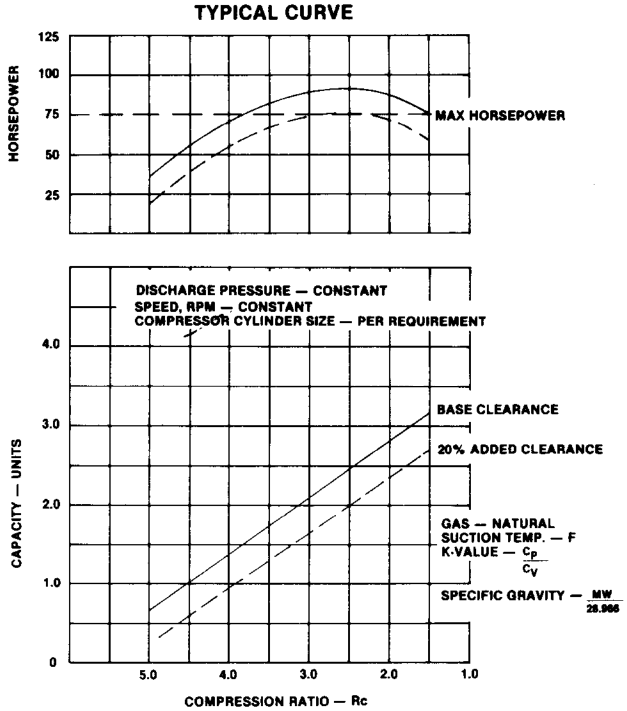

FIGURE 2