ENERGY EFFICIENCY IN THE OILFIELD

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Abstract

Many stripper wells under beam pump operations are operating at or near the economic limit and, without application of available technologies for improved operation to reduce lifting costs, these wells are candidates for abandonment. This possible abandonment creates significant opportunities and challenges for domestic oil operators. A major operating expense is energy cost which requires the operator to maximize energy efficiency. This requires the technical expertise in identifying methods to optimize operations and technologies to increase energy efficiency in field operations.

The objective of this paper is to describe 1) typical operating expenses in domestic oil fields, and 2) a procedure to identify areas where energy usage could be reduced in an oil field or well. The procedure is broken down into non-field and field activities. It describes a screening procedure to determine if operators have candidate wells and oilfield systems where electrical efficiency can be improved. Topics addressed are 1) power tariffs and marginal well service riders, 2) power factor, 3) rate and demand reduction, and 4) improved efficiency through proper motor sizing.

Operating Expenses

Typical operating expenses include 1) energy costs, 2) chemical costs, 3) replacement parts, 4) well workovers, and 5) cost of labor or service. The following table is a breakdown of typical operating expenses and the percent range each item contributes to the overall operating expenditures on an oilwell. Four of the five categories are affected by high water production or high water-oil ratios. The ranges of costs for each category varies depending on the depth of reservoir, fluids produced, corrosion and scale problems, and pump and motor efficiencies. If a reservoir is being waterflooded or operating under a natural water-drive, electrical costs are a larger percent of the overall costs, since water is being injected at high pressures in injection wells creating the oil producing mechanism resulting in larger volumes of produced fluids.

Typical Operating Expenses

Range	Breakdown
15% - 50%	* electricity or energy costs
5% - 15%	* chemicals costs
5% - 15%	* valves, fittings, belts
10% - 40%	* workovers (pulling units)
15% - 40%	* service (labor)

* - Affected by High Water-Oil Ratios

Figure 1 presents a typical stripper well production curve and the economic limit based on two operating costs scenarios. The decline curve is an extrapolation of oil production based on the known oil production. Based on this decline curve, a reduction of 33% in operating costs will extend the economic life of this well over two years. In waterdrive reservoirs, the decline curves tend to be much more horizontal (flatter) which would tend to increase the economic life longer that two years at a given reduction in operating costs.

The electrical costs are dependent upon the following factors; 1) beam pump efficiency, 2) depth of oil reservoir, 3) density and amount of fluids produced, 4) power factors, and 5) electric costs rate schedules. In the past typical practice has been to design pumping units based on optimistic production rates which causes oversizing of motors and beam pumps, resulting in inefficient pumping units. This problem is escalated when the well starts declining in production. This problem can be reduced if producing units and prime movers are redesigned after careful economic analysis. Also, oversized prime movers lower power factors, resulting in penalties on the electric bill.

The chemical costs are dependent upon the severity of the following problems; 1) scale, 2) paraffin, 3) oil and water emulsions, 4) corrosion tendencies, 5) fluid compatibilities and 6) the chemical companies in the oil producing area. In some instances, operators can reduce costs by purchasing bulk chemicals from large supply houses, thus eliminating the chemical companies. However this may be only feasible if no chemical mixing is required and the operator knows the chemicals necessary to correct their problem which is not typical. Typical practice is to contact a chemical company in the area and the representative provides recommendations after testing the oil and water.

Well workovers involve repairing the downhole pump, fishing parted sucker rods, or cleaning the well. In many instances, it requires that the pump and sucker rods be removed from the well for inspection and/or repair. After removal of the downhole equipment, the well can be cleaned utilizing a variety of methods or chemical treatments. The frequency and cost of workovers is dependent upon oil and brine characteristics, depth of reservoir and the amount of fluid produced. In deep wells located in areas having poor access, a pulling job could cost over thousands of dollars and have considerable downtime. In shallow wells, a pulling job could costs as low as $500 with a downtime of less than one day. These factors should be considered when utilizing technologies to reduce workover frequency.

The costs of valves, fittings, belts, beam pump units and workovers are basically constant and can only be reduced by reducing the amount of fluid being produced, i.e., water or implementing a maintenance program by the pumpers. However, reducing the strokes per minute on a pumping unit is the main way to reduce the cost of this category.

The cost of labor is basically fixed.

Oilfield Energy Optimization Program

When conducting an energy optimization program, two types of problems must be identified and solved: field oriented problems at the well and non-field problems such as unnecessary high utility rates. This section is broken down in both areas for simplification. Each section is an important part and interrelates with the other, as presented in Figure 2. For instance, power factor penalties can be identified by reviewing electric utility invoices and measurements in the field.

This program should be conducted on an annual basis or when field operations change dramatically. Figure 3 and 4 presents routine steps that an oilfield manager must implement to reduce the energy costs in the oilfield. Several of the steps also improve overall efficiency of field operations other than energy costs such as reduction in workovers, and wear on equipment.

Non-field and Utility Rate Problems

1) Route all electric utility invoices across desk for examination.

This step involves determining the monthly electricity bill for each field or producing unit. Obviously, the field operations personnel will know the total monthly electricity bill, but often will not know the individual monthly bills for nearby fields or whether electric power is being purchased under the best possible rate schedule. A data base should be developed which provides immediate access to the billing data for any specific location. The billing data should include total cost, electricity demand in kilowatts, energy consumed in kilowatt-hours, and power factor, all of which are listed on the monthly electricity bill. (Barrick, 1994)

2) Obtain copies of all applicable rate schedules from the utility companies involved and contact the marketing departments.

This step involves obtaining rate schedules from the utility companies. These rate schedules will provide the manager with information and ideas on how he might reduce the rate on a particular field.

Electric utilities sell electricity at different prices, depending on the quantity and voltage level of the power being purchased. Generally, large quantities of power at high voltages can be purchased at the lowest cost. The amount of load required to be considered for a high voltage rate varies from utility to utility. Electricity loads in excess of 5,000 to 7,500 kW at a voltage of 69 kV or higher, generally are considered for high-voltage- or industrial-rate schedules. The ability to change to a high-voltage-rate schedule typically results in a 10 to 15% reduction in annual costs, because demand charges and fuel adjustment factors are much lower than for other rate schedules.

3) Make sure all electrified operations are on the lowest economic rate available. Identify any marginal well service riders available.

If an operator finds that their electricity costs in a given location are a candidate for high-voltage- or and industrial-rate schedule, the operator should consider the possibility of building an electric substation. Although existing operations may not qualify for some rates, it may be possible to modify operations to take advantage of a lower rate schedule. It may be possible to consolidate two or more fields to accumulate the necessary minimum load.

Another technique might be to renegotiate the contract to improve the rate schedule. This involves understanding the electric utilities's rate schedules, rate basis, construction planning, fuel mix, fuel cost, load growth history, customer base, and other areas. These items are important because contract renegotiation is most effective and most profitable when the producing company understands what the electric utility can realistically contribute in relation to what the producing company desires, so that the resulting arrangement is mutually beneficial.

Electricity is purchased according to energy and demand. The energy component is merely the total kilo-watt-hours consumed during the billing period. Demand is based on the maximum kilowatt usage for a short term, usually 15 to 30 minutes, or for an average maximum of several short intervals over the billing period. Cyclic and intermittent operation of electric motors will result in uneven demand consumption, which results in a higher unit cost in cents per kilo-watt-hour because of high-demand charges. Load factor is a term used to describe the uniformity of demand usage. Load factor expressed as a percentage, is obtained by dividing the average demand over a billing period by the peak demand. A load factor approaching 100% would mean that all the electricity loads on a system operated continuously and without variation over the billing cycle.

The goal of the producing company is to improve the uniformity of usage to obtain the lowest per-unit cost of electricity. The most common method of ensuring an even demand is through the use of time-delay starters on all wells equipped with electric motors in large fields. This not only prevents excessive demand as the many prime movers are restarted when electric service is returned after power failures but also will protect the distribution system against excessive voltage drops with the resultant low motor-starting torques. Pumpoff controllers should not be permitted to start pumping unit simultaneously because this can cause a high peak demand.

Parameters which effect Rate Schedule

Different electric companies or cooperatives provide service to oil producing areas of the state. Basically, there are four separate charges on most tariffs: power, power factor, demand and fuel adjustment. Recently, utilities have been placing riders on stripper production to reduce rates.

Power Tariffs & Marginal Well Service Riders

Current tariffs applicable to oil field installations vary within companies between $0.038/kwh to $0.90/kwh. Each company's tariff displays different break points for service charges, but the charge for power averages approximately $0.041/kwh.

Recently, selected utilities have been placing riders on marginal oil wells to reduce the cost of electricity. It is a financial arrangement to provide the oil producer a discount during periods of low oil prices, and allows him to repay that discount during periods of higher oil prices. The discount is tracked in kilowatt hours on a per meter basis. All kilowatt hours delivered through a meter at the discounted rate are traced in an account. When the price of oil goes above the agreed price, kilowatt hours delivered through that meter are charged a premium until the account is deleted. Within the repayment calculation there is an adjustment to kilowatt hours that is predicated on an annual interest rate of eight percent. If a marginal property is plugged before prices return to the premium level, the utility collects nothing.

4) Verify accuracy of billing:
   a) Make sure all appropriate credits are being applied. (Primary service discount)
   b) Check for existing deduct meters and make sure those values are being deducted, both KWh and KW.
   c) Check computations periodically.
   d) Make sure proper rate schedule is being applied.

5) Establish and maintain regular and frequent contact with utility companies.

6) Consider demand control, interruptible, and time of day rates where possible.

Billing demand is the maximum kW demand established by the consumer for any period of fifteen (15) consecutive minutes during the month for which the bill is rendered, as indicated or recorded by the demand meter and adjusted for power factor. In computing charges for electric services, no bill for any month is less than sixty-five percent (65%) of the highest maximum demand established during the previous summer season (May through September).

Field Steps

1) Identify normal existing fluid production from each well.

The fundamentals of beam pumping design involve, 1) predicting well performance, 2) sizing pumping system for expected producing conditions, 3) calculating polished rod horsepower, 4) determining brake horsepower, and 5) selection of prime mover. For maximum efficiency the pumping system and prime mover must not be oversized or undersized. Predicting well performance in new wells involves calculations utilizing drill stem test, completion data, and transient test data. However since this program involves optimizing current operations, it will be assumed that well performance and expected producing conditions are already known. Prediction of well performance will not be discussed in this program.

Since the well performance can be assumed from current production rates, pumping units and motors can be properly sized to optimum efficiency.

2) Identify beam pump unit sizes for each well.

3) Conduct API calculations to determine if beam pumps can be resized economically, i.e., Can the capital cost of the resizing unit be recovered in approximately two years.

Because of the wide use of beam pumping systems, the methods for design and analysis of rod pumping installations are being refined and improved continually. The method most simple to apply is the API (analog) method which provides a means both to design and to analyze pumping installations. When utilizing this method, the assumptions must be taken into account and considered. It is recommended that the reader refer to the API bulletin titles "API recommended Practice for Design Calculations for Sucker Rod Pumping Systems". Another excellent reference is by Gibbs, S.G., 1982.

4) Conduct dynamometer tests or electrical current analysis to improve efficiency by resizing unit/motors or balancing unit.

The cyclic nature of the pumping system and the variable loading which is dependent on the mechanics and efficiency of the down-hole pump and sucker rod string, result in a continuously variable current flow over a pumping cycle. This translates in the fact that average values of apparent current are not indicative of the actual power usage and requirements. Moreover to reduce torque loading, counterbalancing of the rod load plus one half of the fluid load is commonly used and most installations exhibit torque reversals during the pumping cycle even if properly balanced. This means that during portions of a pump stroke the prime mover drives the gear box and that during other portions the gearbox drives the motor. In the first case the motor is using electrical power, in the second case it is generating electricity. The most common indication that this reversal in current flow is the clanking sound which may be noted in the gearbox at such times is due to the transfer of load from the front side to the back side of the gear teeth. The conventional clamp-on current meter (transformer) is incapable of differentiating between the current flowing from the line to the motor or from the motor to the power line. In order to determine the actual power utilization it is necessary to make additional measurements that yield information regarding the instantaneous power factor and voltage. Such measurements are not commonly made because of the complexity and cost of the equipment. (McCoy, J., et al, 1993)

The horsepower required at the polished rod on an existing well can be determined through dynamometer measurements, electric current analysis, or computation methods. Each have their advantages. Dynamometer measurements at the well tend to be the most accurate, however they are time consuming and costs are relatively high. Electric current analysis at the well tend to be less accurate than dynamometer measurements, however are less costly and time consuming. Computation methods are least accurate, however are typically used for initial motor sizing and resizing. The computational methods assumes optimal conditions and do not take into account individual well operating characteristics. For the purpose of this program, the computation method and electric current analysis will be described.

The Department of Energy has developed a database on motors called Motor Master. It covers the economic and operational factors to be considered when motor purchase decisions are being made. Another reference which discusses both oil field motor efficiency and Motor Master is titled: "Methodology for Increasing the Efficiency of Electric Motors in Oil Fields" (Ula and Buren, 1994)

Various computation methods exist (Zaba, and Doherty, 1956), (API Bulletin RP11L, 1972), (Howell, and Hogwood, 1962), however the most used is based on computation of hydraulic horsepower and subsurface friction horsepower requirements, adjusted for surface equipment inefficiencies and cyclic load (Cornelison and Kosmark, 1977).

5) If power factors are low after resizing units and motors, conduct calculations to determine if capacitor banks are economical.
   a) If economical, install secondary power factor correction capacitors at wells. Be careful not to overcorrect, as this may result in damage to motors.
   b) Install power factor correction capacitors on primary lines if secondary correction was not sufficient to bring power factor above penalty level.

6) Resize transformers and place in locations which reduce the lowest line losses. Always use a qualified and competent electrical contractor or consultant to assist in prudent design philosophy.

Conclusion

An energy optimization program has been developed which is broken down into field and non-field activities. The program can be utilized to reduce other operating costs other than energy by streamlining operations.

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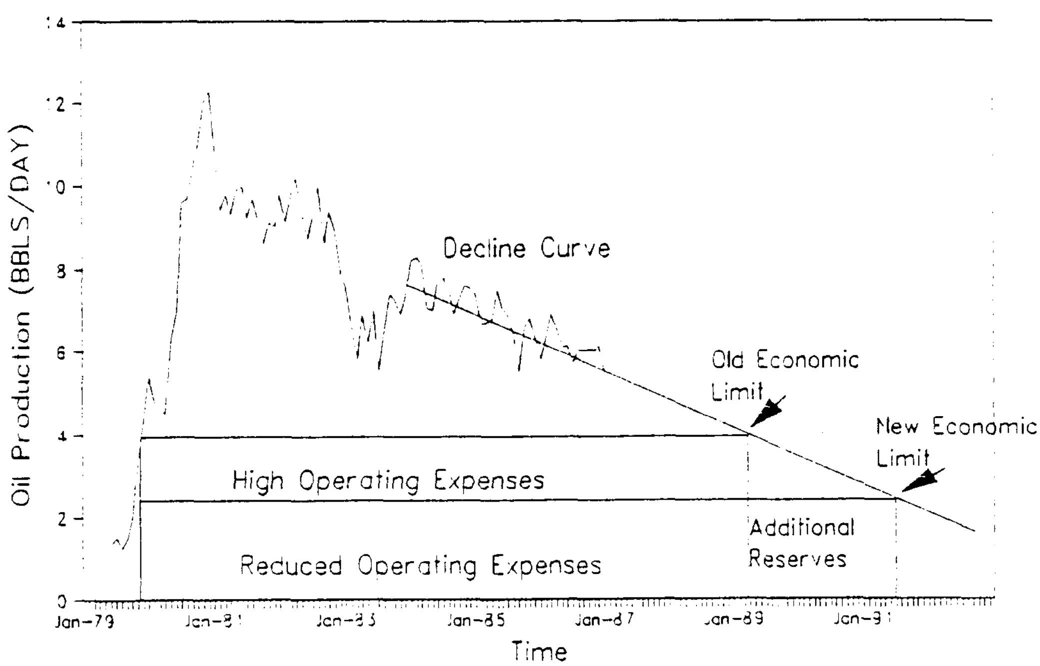

Figure 1 - An increase in economic life of a well as a result of decreased operating expenses. Typical Stripper Well Oil Prod. Decline

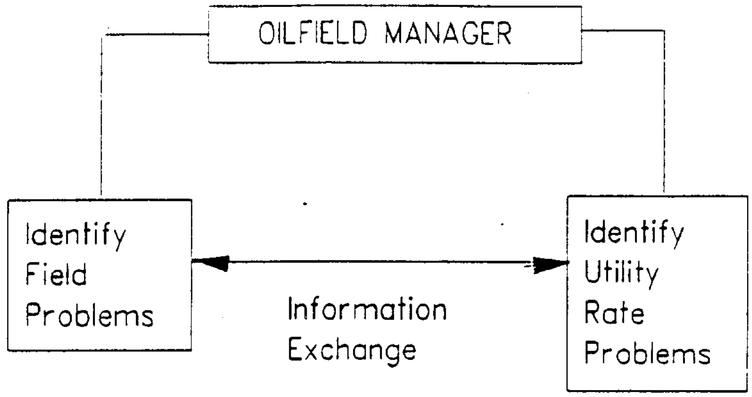

Figure 2 - The two types of problems the oilfield manager must identify

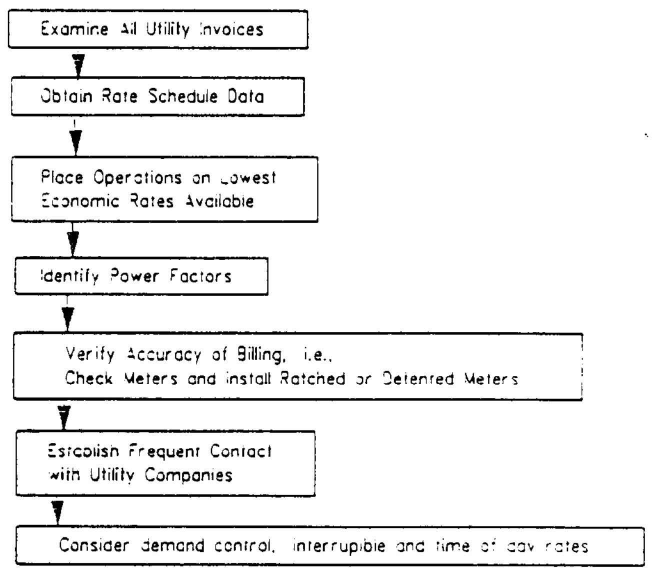

Figure 3 - Identification of utility rate problems

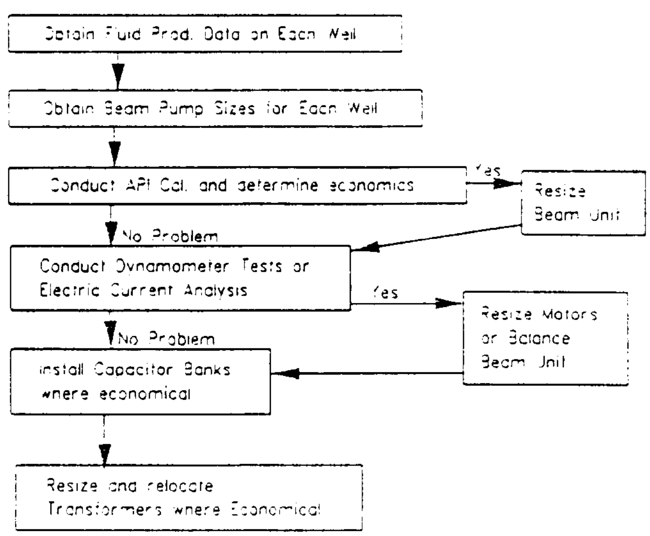

Figure 4 - Identification of field problems