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# **Energy Efficiency Improvement Opportunities for the Petroleum Refining Industry**

*Ernst Worrell, Christina Galitsky, Lynn Price, Nathan  
Martin, Michael Ruth*

**Environmental Energy Technologies Division**

*R.Neal Elliott, Anna Shipley, J.Thorne*

**American Council for an Energy-Efficient Economy**

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# Energy Efficiency Improvement Opportunities for the Petroleum Refining Industry

Environmental Energy Technologies Division  
Lawrence Berkeley National Laboratory

This report provides information on the energy savings, costs, and carbon dioxide emissions reductions associated with implementation of a number of technologies and measures applicable to the petroleum refining industry. The technologies and measures include both state-of-the-art measures that are currently in use in refineries worldwide as well as advanced measures that are either only in limited use or are near commercialization.

This report focuses on retrofit measures using commercially available technologies, but many of these technologies are applicable for new plants as well. For each technology or measure, costs and energy savings per barrel of product are estimated in the text following the Tables 1 to 3. Table 1 lists all cross cutting and utility measures in this report by process to which they apply. Table 2 provides all process-specific energy efficiency opportunities grouped by process. Table 4 provides a matrix for the petroleum refining industry as organized in this report for each major process in the refinery (in rows) and the applicable categories of energy efficiency measures delineated in sections of this report (in columns).

Advanced technologies and measures for reducing energy use and carbon dioxide emissions include membrane technologies, dividing-wall distillation, reactive distillation and biodesulfurization. In the petroleum refining industry, these technologies are currently not in commercial use or are still expanding into new areas (e.g., membranes, dividing-wall distillation).

This information was originally collected for a report on the U.S. petroleum refining industry (Worrell and Galitsky, 2005) and has been supplemented with information from Martin et al. (2000) and Worrell and Galitsky (2004). The information provided in this report is based on publicly-available reports, journal articles, and case studies from applications of technologies around the world, however, data for energy savings, costs, and carbon emissions savings were all calculated based on U.S. conditions.

Table 1. Summary of energy efficiency opportunities for utilities and cross-cutting energy uses for the petroleum refining industry

<b>Management &amp; Control</b>	<b>Motors</b>
Energy monitoring Site energy control systems	Proper sizing of motors High efficiency motors
<b>Energy Recovery</b>	Power factor control
Flare gas recovery Power recovery Hydrogen recovery Hydrogen pinch analysis	Voltage unbalance Adjustable speed drives Variable voltage controls Replace belt drives
<b>Boilers</b>	<b>Pumps</b>
Boiler feedwater preparation Improved boiler controls Reduced flue gas volume Reduced excess air Improve insulation Maintenance Flue gas heat recovery Blowdown heat recovery Reduced standby losses	Operations & maintenance Monitoring More efficient pump designs Correct sizing of pumps Multiple pump use Trimming impeller Controls Adjustable speed drives Avoid throttling valves Correct sizing of pipes
<b>Steam Distribution</b>	Reduce leaks Sealings Dry vacuum pumps
Improved insulation Maintain insulation Improved steam traps Maintain steam traps Automatic monitoring steam traps Leak repair Recover flash steam Return condensate	<b>Compressed Air</b>
<b>Heaters and Furnaces</b>	Maintenance Monitoring Reduce leaks Reduce inlet air temperature Maximize allowable pressure dew point Controls Properly sized regulators Size pipes correctly Adjustable speed drives Heat recovery for water preheating
Maintenance Draft control Air preheating Fouling control New burner designs	
<b>Process Integration</b>	<b>Fans</b>
Total site pinch analysis Water pinch analysis	Properly sizing Adjustable speed drives
<b>Distillation</b>	High-efficiency belts
Optimized operation procedures Optimized product purity Seasonal pressure adjustments Reduced reboiler duty Upgraded column internals	<b>Lighting</b> Lighting controls T8 Tubes Metal halides/High-pressure sodium High-intensity fluorescent (T5) Electronic ballasts Reflectors LED exit signs
	<b>Power Generation</b>
	CHP (cogeneration) Gas expansion turbines High-Temperature CHP Gasification (Combined Cycle)

Table 2. Summary of process-specific energy efficiency opportunities for the petroleum refining industry

<b>Desalter</b>	<b>Hydrocracker</b>
Multi-stage desalters Combined AC/DC fields	Power recovery Process integration (pinch)
<b>Crude Distillation Unit</b>	Furnace controls Air preheating Optimization distillation
Process controls High-temperature CHP Process integration (pinch) Furnace controls Air preheating Progressive crude distillation Optimization distillation	<b>Coking</b>
<b>Vacuum Distillation Unit</b>	Process integration (pinch) Furnace controls Air preheating
Process controls Process integration (pinch) Furnace controls Air preheating Optimization distillation	<b>Visbreaker</b>
<b>Hydrotreater</b>	Process integration (pinch) Optimization distillation
Process controls Process integration (pinch) Optimization distillation New hydrotreater designs	<b>Alkylation</b>
<b>Catalytic Reformer</b>	Process controls Process integration (pinch) Optimization distillation
Process integration (pinch) Furnace controls Air preheating Optimization distillation	<b>Hydrogen Production</b>
<b>FCC</b>	Process integration (pinch) Furnace controls Air preheating Adiabatic pre-reformer
Process controls Power recovery Process integration (pinch) Furnace controls Air preheating Optimization distillation Process flow changes	<b>Other</b>
	Optimize heating storage tanks Optimize flares

Table 3. Matrix of energy efficiency opportunities in petroleum refineries. For each major process in the refinery (in rows) the applicable categories of energy efficiency measures are denoted (in columns).

Process	Energy Management	Flare Gas Recovery	Power Recovery	Boilers	Steam Distribution	Heat Exchanger	Process Integration	Process Heaters	Distillation	Hydrogen Management	Motors	Pumps	Compressed Air	Fans	Lighting	Cogeneration	Power Generation	Other Opportunities
Desalting	X											X						
CDU	X	X			X	X	X	X	X		X	X		X				
VDU	X				X	X	X	X	X					X				
Hydrotreater	X				X	X	X	X	X	X				X				
Catalytic Reformer	X	X			X	X	X	X	X	X				X				
FCC	X	X	X		X	X	X	X	X					X				
Hydrocracker	X	X	X		X	X	X	X	X	X				X				
Coker	X	X			X	X	X	X	X					X				
Visbreaker	X	X			X	X	X	X	X					X				
Alkylation	X				X	X	X	X	X					X				
Light End	X				X	X	X		X									
Aromatics	X				X	X	X	X	X									
Hydrogen	X				X	X	X	X		X				X				
Utilities	X	X	X	8.1	X	X	X			X			X	X	X	X	X	X

## Overall Measures

**Monitoring and control systems** can play an important role in energy management and in reducing energy use. These may include sub-metering, monitoring and control systems. They can reduce the time required to perform complex tasks, often improve product and data quality and consistency, and optimize process operations. Typically, energy and cost savings are around 5% or more for many industrial applications of process control systems. These savings apply to plants without updated process control systems; many refineries may already have modern process control systems in place to improve energy efficiency.

Although energy management systems are already widely disseminated in various industrial sectors, the performance of the systems can still be improved, reducing costs and increasing energy savings further. For example, total site energy monitoring and management systems can increase the exchange of energy streams between plants on one site. Traditionally, only one process or a limited number of energy streams were monitored and managed. Various suppliers provide site-utility control systems (HCP, 2001).

Specific energy savings and payback periods for overall adoption of an energy monitoring system vary greatly from plant to plant and company to company.

A variety of process control systems are available for virtually any industrial process. A wide body of literature is available assessing control systems in most industrial sectors such as chemicals and petroleum refining. Table 4 provides an overview of classes of process control systems.

*Table 4. Classification of control systems and typical energy efficiency improvement potentials.*

System	Characteristics	Typical energy savings (%)
Monitoring and Targeting	Dedicated systems for various industries, well established in various countries and sectors	4-17 (average 8%) (based on experiences in the UK)
Computer Integrated Manufacturing (CIM)	Improvement of overall economics of process, e.g., stocks, productivity and energy	> 2
Process control	Moisture, oxygen and temperature control, air flow control "Knowledge based, fuzzy logic"	2-18

Note: The estimated savings are valid for specific applications (e.g., lighting energy use). The energy savings cannot be added, due to overlap of the systems. Sources: (Caffal 1995, Martin et al., 2000).

Modern control systems are often not solely designed for energy efficiency, but rather for improving productivity, product quality, and the efficiency of a production line. Applications of advanced control and energy management systems are in varying development stages and can be found in all industrial sectors. Control systems result in reduced downtime, reduced maintenance costs, reduced processing time, and increased resource and energy efficiency, as well as improved emissions control. Many modern energy efficient technologies depend heavily on precise control of process variables, and applications of process control systems are growing rapidly. Modern process control systems exist for virtually any industrial process, and, within a refinery, virtually all

processes, as well as for management of refinery fuel gas, hydrogen, and total site control. Still, large potentials exist to implement control systems and more modern systems enter the market continuously. *Hydrocarbon Processing* produces a semi-annual overview of new advanced process control technologies for the oil refining industry (see e.g., HCP, 2001). Below examples of processes and site-wide process control systems are discussed, selected on the basis of available case studies to demonstrate the specific applications and achieved energy savings

Process control systems depend on information from many stages of the processes. A separate but related and important area is the development of sensors that are inexpensive to install, reliable, and analyze in real-time. Current development efforts are aimed at the use of optical, ultrasonic, acoustic, and microwave systems, that should be resistant to aggressive environments (e.g., oxidizing environments in furnace or chemicals in chemical processes) and withstand high temperatures. The information of the sensors is used in control systems to adapt the process conditions, based on mathematical (“rule”-based) or neural networks and “fuzzy logic” models of the industrial process.

Neural network based control systems have successfully been used in the cement (kilns), food (baking), non-ferrous metals (alumina, zinc), pulp and paper (paper stock, lime kiln), petroleum refineries (process, site), and steel industries (electric arc furnaces, rolling mills). New energy management systems that use artificial intelligence, fuzzy logic (neural network), or rule-based systems mimic the “best” controller, using monitoring data and learning from previous experiences.

Process knowledge based systems (KBS) have been used in design and diagnostics, but are hardly used in industrial processes. Knowledge bases systems incorporate scientific and process information applying a reasoning process and rules in the management strategy. A recent demonstration project in a sugar beet mill in the UK using model based predictive control system demonstrated a 1.2 percent reduction in energy costs, while increasing product yield by almost one percent and reducing off-spec product from 11 percent to four percent. This system had a simple payback period of 1.4 years (CADDET, 2000).

Research for advanced sensors and controls in the U.S. is ongoing in all sectors, both funded with public funds and private research. Japan and Europe also give much attention to advanced controls. Several projects within U.S. DOE’s Industries of the Future program try to develop more advanced control technologies (U.S. DOE-OIT, 2000a). Sensors and control techniques are identified as key technologies in various development areas including energy efficiency, mild processing technology, environmental performance and inspection, and containment boundary integrity. Future steps include further development of new sensors and control systems, demonstration in commercial scale, and dissemination of the benefits of control systems in a wide variety of industrial applications.

**Refinery Wide Optimization.** Total site energy monitoring and management systems (Kawano, 1996) can increase the exchange of energy streams between plants on one site.



Traditionally, only one plant or a limited number of energy streams were monitored and managed. Various suppliers provide site-utility control systems (HCP, 2001). Valero and AspenTech have developed a plant-wide energy optimization model to optimize the flows of intermediates, hydrogen, steam, fuel and electricity use, integrated with an energy monitoring system. The optimization system includes the cogeneration unit, FCC power recovery, and optimum load allocation of boilers, as well as selection of steam turbines or electric motors to run compressors. The system was implemented at Valero's Houston, Texas (U.S.) refinery in 2003 and is expected to reduce overall site-wide energy use by 2-8%. Company wide, Valero expects to save \$7-\$27 million annually at 12 refineries (Valero, 2003).

**CDU.** A few companies supply control equipment for CDUs. Aspen technology has supplied over 70 control applications for CDUs and 10 optimization systems for CDUs. Typical cost savings are \$0.05 - \$0.12/bbl of feed, with paybacks less than 6 months. Key Control supplies an expert system advisor for CDUs. It has installed one system at a CDU, which resulted in reduced energy consumption and flaring and increased throughput with a payback of 1 year.

Installation of advanced control equipment at Petrogals Sines refinery in Portugal on the CDU resulted in increased throughputs of 3-6% with a payback period of 3 months.

**FCC.** Several companies offer FCC control systems, including ABB Simcon, AspenTech, Honeywell, Invensys, and Yokogawa. Cost savings may vary between \$0.02 and \$0.40/bbl of feed with paybacks between 6 and 18 months.

Timmons et al. (2000) report on the advantages of combining an online optimizer with an existing control system to optimize the operation of a FCC unit at the CITGO refinery in Corpus Christi, Texas, U.S. The Citgo refinery installed a modern control system and an online optimizer on a 65,000 bpd FCC unit. The combination of the two systems was effective in improving the economic operation of the FCC. The installation of the optimizer led to additional cost savings of approximately \$0.05/barrel of feed to the FCC, which resulted in an attractive payback (Timmons et al., 2000).

The ENI refinery in Sanassazzo (Italy) installed in 2001 an optimizer on a FCC unit from Aspen Technology. The system resulted in cost savings of \$0.10/bbl with a payback of less than one year.

**Hydrotreater.** Installation of a multivariable predictive control (MPC) system was demonstrated on a hydrotreater at a SASOL refinery in South Africa. The MPC aimed to improve the product yield while minimizing the utility costs. The implementation of the system led to improved yield of gasoline and diesel, reduction of flaring, and a 12% reduction in hydrogen consumption and an 18% reduction in fuel consumption of the heater (Taylor et al., 2000). Fuel consumption for the reboiler increased to improve throughput of the unit. With a payback period of 2 months, the project resulted in improved yield and in direct and indirect (i.e., reduced hydrogen consumption) energy efficiency improvements.

**Alkylation.** Motiva's Convent, Louisiana (U.S.) refinery implemented an advanced control system for their 100,000 bpd sulfuric acid alkylation plant. The system aims to increase product yield (by approximately 1%), reduce electricity consumption by 4.4%, reduce steam use by 2.2%, reduce cooling water use by 4.9%, and reduce chemicals consumption by 5-6% (caustic soda by 5.1%, sulfuric acid by 6.4%) (U.S. DOE-OIT, 2000a). The software package integrates information from chemical reactor analysis, pinch analysis, information on flows, and information on energy use and emissions to optimize efficient operation of the plant. No economic performance data was provided, but the payback is expected to be rapid as only additional computer equipment and software had to be installed. The program is available through the Gulf Coast Hazardous Substance research Center and Louisiana State University (U.S.). Other companies offering alkylation controls are ABB Simcon, Aspen technology, Emerson, Honeywell, Invensys, and Yokogawa. The controls typically result in cost savings of \$0.10 to \$0.20/bbl of feed with paybacks of 6 to 18 months.

### *Energy Recovery*

**Flare gas recovery** (or zero flaring) is a strategy evolving from the need to improve environmental performance. Conventional flaring practice has been to operate at some flow greater than the manufacturer's minimum flow rate to avoid damage to the flare (Miles, 2001). Typically, flared gas consists of background flaring (including planned intermittent and planned continuous flaring) and upset-blowdown flaring. In offshore flaring, background flaring can be as much as 50% of all flared gases (Miles, 2001). In refineries, background flaring will generally be less than 50%, depending on practices in the individual refinery. Recent discussions on emissions from flaring by refineries located in the San Francisco Bay Area, CA (U.S.) have highlighted the issue from an environmental perspective (Ezerksy, 2002).<sup>1</sup> The report highlighted the higher emissions compared to previous assumptions of the Air Quality District, due to larger volumes of flared gases. The report also demonstrated the differences among various refineries, and plants within the refineries. Reduction of flaring will not only result in reduced air pollutant emissions, but also in increased energy efficiency replacing fuels, as well as less negative publicity around flaring.

Emissions can be further reduced by improved process control equipment and new flaring technology. Development of gas-recovery systems, development of new ignition systems with low-pilot-gas consumption, or elimination of pilots altogether with the use of new ballistic ignition systems can reduce the amount of flared gas considerably (see also Other Opportunities Section). Development and demonstration of new ignition systems without a pilot may result in increased energy efficiency and reduced emissions.

Reduction of flaring can be achieved by improved recovery systems, including installing recovery compressors and collection and storage tanks. This technology is commercially

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<sup>1</sup> ChevronTexaco commented on the report by the Bay Area Air Quality Management District on refinery flaring. The comments were mainly directed towards the VOC-calculations in the report and an explanation of the flaring practices at the ChevronTexaco refinery in Richmond, CA (Hartwig, 2003).

available. Various refineries in the United States have installed flare gas recovery systems, e.g., ChevronTexaco in Pascagoula, Mississippi (U.S.) and even some small refineries like Lion Oil Co. (El Dorado, Arkansas, U.S.). A plant-wide assessment of the Equilon refinery in Martinez, CA (U.S.; fully owned by Shell) highlighted the potential for flare gas recovery. The refinery will install new recovery compressors and storage tanks to reduce flaring. No specific costs were available for the flare gas recovery project, as it is part of a large package of measures for the refinery. The overall project has projected annual savings of \$52 million and a payback period of 2 years (U.S. DOE-OIT, 2002a).

Installation of two flare gas recovery systems at the 65,000 bpd Lion Oil Refinery in El Dorado, Arkansas (U.S.) in 2001 has reduced flaring to near zero levels (Fisher and Brennan, 2002). The refinery will only use the flares in emergencies where the total amount of gas will exceed the capacity of the recovery unit. The recovered gas is compressed and used in the refineries fuel system. No information on energy savings and payback were given for this particular installation. John Zink Co., the installer of the recovery system, reports that the payback period of recovery systems may be as short as one year. Furthermore, flare gas recovery systems offer increased flare tip life and emission reductions.

**Power Recovery.** Various processes run at elevated pressures, enabling the opportunity for power recovery from the pressure in the flue gas. The major application for power recovery in the petroleum refinery is the fluid catalytic cracker (FCC). However, power recovery can also be applied to hydrocrackers or other equipment operated at elevated pressures. Modern FCC designs use a power recovery turbine or turbo expander to recover energy from the pressure. The recovered energy can be used to drive the FCC compressor or to generate power. Power recovery applications for FCC are characterized by high volumes of high temperature gases at relatively low pressures, while operating continuously over long periods of time between maintenance stops (> 32,000 hours). There is wide and long-term experience with power recovery turbines for FCC applications. Various designs are marketed, and newer designs tend to be more efficient in power recovery. Recovery turbines are supplied by a small number of global suppliers, including GE Power Systems.

Many refineries around the world have installed recovery turbines. Valero has recently upgraded the turbo expanders at its Houston and Corpus Christi, Texas and Wilmington, California (all U.S.) refineries. Valero's Houston Refinery replaced an older power recovery turbine to enable increased blower capacity to allow an expansion of the FCC. At the Houston refinery, the re-rating of the FCC power recovery train led to power savings of 22 MW (Valero, 2003), and will export additional power (up to 4 MW) to the grid. Petro Canada's Edmonton refinery replaced an older turbo expander by a new more efficient unit in October 1998, saving around 19 PJ (18 Tbtu) annually.

Power recovery turbines can also be applied at hydrocrackers. Power can be recovered from the pressure difference between the reactor and fractionation stages of the process. In 1993, the Total refinery in Vlissingen (the Netherlands) installed a 910 kW power

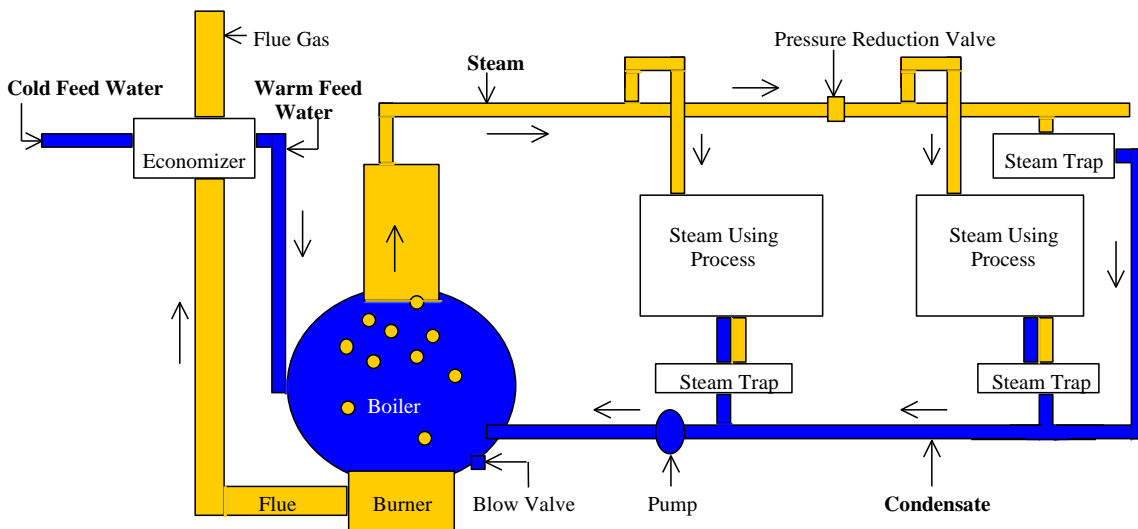
recovery turbine to replace the throttle at its hydrocracker, operating at 160 bar. The power recovery turbine produces about 7.3 million kWh/year (assuming 8000 hours/year). The investment was equal to \$1.2 million (1993\$). This resulted in a payback period of approximately 2.5 years at the conditions in the Netherlands (CADET, 2003).

*Steam Generation and Distribution*

Steam is used throughout the refinery. Steam can be generated through waste heat recovery from processes, cogeneration, and boilers. While the exact size and use of a modern steam system varies greatly, there is an overall pattern that steam systems follow, as shown in Figure 1.

Figure 1 depicts a schematic presentation of a steam system. Treated cold feed water is fed to the boiler, where it is heated to form steam. Chemical treatment of the feed water is required to remove impurities. The impurities would otherwise collect on the boiler walls. Even though the feed water has been treated, some impurities still remain and can build up in the boiler water. As a result, water is periodically drained from the bottom of the boiler in a process known as blowdown. The generated steam travels along the pipes of the distribution system to get to the process where the heat will be used. Sometimes the steam is passed through a pressure reduction valve if the process requires lower pressure steam. As the steam is used to heat processes, and even as it travels through the distribution system to get there, the steam cools and some is condensed. This condensate is removed by a steam trap, which allows condensate to pass through, but blocks the passage of steam. The condensate can be recirculated to the boiler, thus recovering some heat and reducing the need for fresh treated feed water. The recovery of condensate and blowdown will also reduce the costs of boiler feed water treatment. For example, optimization of blowdown steam use at Valero’s Houston refinery use led to cost savings of \$213,500/year (Valero, 2003).

*Figure 1. Schematic presentation of a steam production and distribution system.*



The refining industry uses steam for a wide variety of purposes, the most important being process heating, drying or concentrating, steam cracking, and distillation. Whatever the use or the source of the steam, efficiency improvements in steam generation, distribution and end-use are possible. A recent study by the U.S. Department of Energy estimates the overall potential for energy savings in petroleum refineries at over 12% (U.S. DOE-OIT, 2002b). It is estimated that steam generation, distribution, and cogeneration offer the most cost-effective energy efficiency opportunities on the short term. This section focuses on the steam generation in boilers (including waste heat boilers) and distribution. Table 5 summarizes the boiler efficiency measures, while Table 6 summarizes the steam distribution system measures.

Steam, like any other secondary energy carrier, is expensive to produce and supply. The use of steam should be carefully considered and evaluated. Often steam is generated at higher pressures than needed or in larger volumes than needed at a particular time. These inefficiencies may lead steam systems to let down steam to a lower pressure or to vent steam to the atmosphere. Hence, it is strongly recommended to evaluate the steam system on the use of appropriate pressure levels and production schedules. If it is not possible to reduce the steam generation pressure, it may still be possible to recover the energy through a turbo expander or steam expansion turbine (see Steam Expansion Turbines Section, below). Excess steam generation can be reduced through improved process integration (see Process Integration Section, below) and improved management of steam flows in the refinery (see Monitoring and Process Control Section, above). Many refineries operate multiple boilers. By dispatching boilers on the basis of efficiency, it is possible to save energy. An audit of the Equilon refinery (now owned by Shell) in Martinez, California (U.S.), found that scheduling of steam boilers on the basis of efficiency (and minimizing losses in the steam turbines) can result in annual energy savings equaling \$5.4 million (U.S. DOE-OIT, 2002a).

*Boilers*

*Table 5. Summary of energy efficiency measures in boilers.*

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Improved Process Control	3%	0.6	Reduced Emissions
Reduced Flue Gas Quantity	2-5%	-	Cheaper emission controls
Reduced Excess Air	1% improvement for each 15% less excess air	-	
Improved Insulation	6-26%	?	Faster warm-up
Boiler Maintenance	10%	0	Reduced emissions
Flue Gas Heat Recovery	1%	2	
Blowdown Steam Heat Recovery	1.3%	1 - 2.7	Reduced damage to structures (less moist air is less corrosive).
Alternative Fuels	Variable	-	Reduces solid waste stream at the cost of increased air emissions

**Boiler Feed Water Preparation.** Depending on the quality of incoming water, the boiler feed water (BFW) needs to be pre-treated to a varying degree. Various technologies may be used to clean the water. A new technology is based on the use of membranes. In reverse osmosis (RO), the pre-filtered water is pressed at increased pressure through a semi-permeable membrane. Reverse osmosis and other membrane technologies are used more and more in water treatment (Martin et al., 2000). Membrane processes are very reliable, but need semi-annual cleaning and periodic replacement to maintain performance.

The Flying J Refinery in North Salt Lake, Utah (U.S.) installed a RO-unit to remove hardness and reduce the alkalinity from boiler feedwater, replacing a hot lime water softener. The unit started operation in 1998, resulting in reduced boiler blowdown (from 13.3% to 1.5% of steam produced) and reduced chemical use, maintenance, and waste disposal costs (U.S. DOE-OIT, 2001a). With an investment of \$350,000 and annual benefits of approximately \$200,000, the payback period amounted to less than 2 years.

**Improved Process Control.** Flue gas monitors are used to maintain optimum flame temperature, and to monitor CO, oxygen and smoke. The oxygen content of the exhaust gas is a combination of excess air (which is deliberately introduced to improve safety or reduce emissions) and air infiltration (air leaking into the boiler). By combining an oxygen monitor with an intake airflow monitor, it is possible to detect (small) leaks. Using a combination of CO and oxygen readings, it is possible to optimize the fuel/air mixture for high flame temperature (and thus the best energy efficiency) and low emissions. The payback of improved process control is approximately 0.6 years (IAC, 1999)<sup>2</sup>. This measure may be too expensive for small boilers.

**Reduce Flue Gas Quantities.** Often, excessive flue gas results from leaks in the boiler and the flue, reducing the heat transferred to the steam, and increasing pumping requirements. These leaks are often easily repaired. Savings amount to 2-5% (U.S. DOE-OIT, 1998). This measure consists of a periodic repair based on visual inspection. The savings from this measure and from flue gas monitoring are not cumulative, as they both address the same losses.

**Reduce Excess Air.** The more air is used to burn the fuel, the more heat is wasted in heating air. Air slightly in excess of the ideal stoichiometric fuel/air ratio is required for safety, and to reduce NO<sub>x</sub> emissions, and is dependent on the type of fuel. For gas and oil-fired boilers, approximately 15% excess air is adequate (U.S. DOE-OIT, 1998; Ganapathy, 1994). Poorly maintained boilers can have up to 140% excess air. Reducing this back down to 15% even without continuous automatic monitoring would save 8%.

**Improve Insulation.** New materials insulate better, and have a lower heat capacity. Savings of 6-26% can be achieved if this improved insulation is combined with improved heater circuit controls. This improved control is required to maintain the output

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<sup>2</sup> The IAC database shows a series of case studies where a particular technology was used. It gives a wide variety of information, including the payback period for each case. We calculated an overall payback for a technology by averaging all the individual cases.

temperature range of the old firebrick system. As a result of the ceramic fiber's lower heat capacity, the output temperature is more vulnerable to temperature fluctuations in the heating elements (Caffal, 1995). The shell losses of a well-maintained boiler should be less than 1%.

**Maintenance.** A simple maintenance program to ensure that all components of the boiler are operating at peak performance can result in substantial savings. In the absence of a good maintenance system, the burners and condensate return systems can wear or get out of adjustment. These factors can end up costing a steam system up to 20-30% of initial efficiency over 2-3 years (U.S. DOE-OIT, 2001a). On average, the possible energy savings are estimated at 10% (U.S. DOE-OIT, 2001a). Improved maintenance may also reduce the emission of criteria air pollutants.

Fouling of the fireside of the boiler tubes or scaling on the waterside of the boiler should also be controlled. Fouling and scaling are more of a problem with coal-fed boilers than with natural gas or oil-fed ones (i.e., boilers that burn solid fuels like coal should be checked more often as they have a higher fouling tendency than liquid fuel boilers do). Tests show that a soot layer of 0.03 inches (0.8 mm) reduces heat transfer by 9.5%, while a 0.18 inch (4.5 mm) soot layer reduces heat transfer by 69% (CIPEC, 2001). For scaling, 0.04 inches (1 mm) of buildup can increase fuel consumption by 2% (CIPEC, 2001). Moreover, scaling may result in tube failures.

**Recover Heat From Flue Gas.** Heat from flue gasses can be used to preheat boiler feed water in an economizer. While this measure is fairly common in large boilers, there is often still potential for more heat recovery. The limiting factor for flue gas heat recovery is the economizer wall temperature that should not drop below the dew point of acids in the flue gas. Traditionally this is done by keeping the flue gases at a temperature significantly above the acid dew point. However, the economizer wall temperature is more dependent on the feed water temperature than flue gas temperature because of the high heat transfer coefficient of water. As a result, it makes more sense to preheat the feed water to close to the acid dew point before it enters the economizer. This allows the economizer to be designed so that the flue gas exiting the economizer is just barely above the acid dew point. One percent of fuel use is saved for every 25°C reduction in exhaust gas temperature (Ganapathy, 1994). Since exhaust gas temperatures are already quite low, limiting savings to 1% across all boilers, with a payback of 2 years (IAC, 1999).

**Recover Steam From Blowdown.** When the water is blown from the high-pressure boiler tank, the pressure reduction often produces substantial amounts of steam. This steam is low grade, but can be used for space heating and feed water preheating. For larger high-pressure boilers, the losses may be less than 0.5%. It is estimated that this measure can save 1.3% of boiler fuel use for all boilers below 100 GJ/hr. The payback period of blowdown steam recovery will vary between 1 and 2.7 years (IAC, 1999).

**Reduce Standby Losses.** In refineries often one or more boilers are kept on standby in case of failure of the operating boiler. The steam production at standby can be reduced to virtually zero by modifying the burner, combustion air supply and boiler feedwater supply. By installing an automatic control system the boiler can reach full capacity within

12 minutes. Installing the control system and modifying the boiler can result in energy savings up to 85% of the standby boiler, depending on the use pattern of the boiler.

The Kemira Oy ammonia plant at Rozenburg (the Netherlands) applied this system to a small 40 t/hr steam boiler, reducing the standby steam consumption from the boiler from 6 t/hr to 1 t/hr. This resulted in energy savings of 57 PJ/year (54 TBtu/year). Investments were approximately \$270,000 (1991\$), resulting in a payback period of 1.5 years at this particular plant (CADET, 1997b).

*Steam Distribution*

*Table 6. Summary of energy efficiency measures in steam distribution systems.*

Measure	Fuel Saved	Payback Period (years)	Other Benefits
Improved Insulation	3-13%	1.1	
Improved Steam Traps	Unknown	Unknown	Greater reliability
Steam Trap Maintenance	10-15%	0.5	
Automatic Steam Trap Monitoring <sup>3</sup>	5%	1	
Leak Repair	3-5%	0.4	Reduced requirement for major repairs
Flash Steam Recovery/ Condensate Return	83% <sup>4</sup>	Unknown	Reduced water treatment costs
Condensate Return Alone	10%	1.1	Reduced water treatment costs

When designing new steam distribution systems, it is very important to take into account the velocity and pressure drop (Van de Ruit, 2000). This reduces the risk of oversizing a steam pipe, which is not only a cost issue but would also lead to higher heat losses. A pipe too small may lead to erosion and increased pressure drop. Installations and steam demands change over time, which may lead to under-utilization of steam distribution capacity utilization, and extra heat losses. However, it may be too expensive to optimize the system for changed steam demands. Still, checking for excess distribution lines and shutting off those lines is a cost-effective way to reduce steam distribution losses. Other maintenance measures for steam distribution systems are described below.

**Improve Insulation.** This measure can be to use more insulating material, or to make a careful analysis of the proper insulation material. Crucial factors in choosing insulating material include: low thermal conductivity, dimensional stability under temperature change, resistance to water absorption, and resistance to combustion. Other characteristics of insulating material may also be important depending on the application, e.g., tolerance of large temperature variations and system vibration, and compressive strength where insulation is load bearing (Baen and Barth, 1994). Improving the insulation on the existing stock of heat distribution systems would save an average of 3-13% in all systems (U.S. DOE-OIT, 1998) with an average payback period of 1.1 years

<sup>3</sup> In addition to a regular maintenance program

<sup>4</sup> Includes flash steam recovery from the boiler. Although this represents actual savings achieved in a case study, it seems much too high to be a generally applicable savings number. As a result, it is not included in our total savings estimate.



(IAC, 1999). The U.S. Department of Energy has developed the software tool 3E-Plus to evaluate the optimal insulation for steam systems.

**Maintain Insulation.** It is often found that after repairs, the insulation is not replaced. In addition, some types of insulation can become brittle, or rot. As a result, energy can be saved by a regular inspection and maintenance system (CIBO, 1998). Exact energy savings and payback periods vary with the specific situation in the plant.

**Improve Steam Traps.** Using modern thermostatic elements, steam traps can reduce energy use while improving reliability. The main advantages offered by these traps are that they open when the temperature is very close to that of the saturated steam (within 2°C), purge non-condensable gases after each opening, and are open on startup to allow a fast steam system warm-up. These traps are also very reliable, and useable for a wide variety of steam pressures (Alesson, 1995). Energy savings will vary depending on the steam traps installed and state of maintenance.

**Maintain Steam Traps.** A simple program of checking steam traps to ensure that they operate properly can save significant amounts of energy. If the steam traps are not regularly monitored, 15-20% of the traps can be malfunctioning. In some plants, as many as 40% of the steam traps were malfunctioning. Energy savings for a regular system of steam trap checks and follow-up maintenance is estimated at up to 10% (U.S. DOE-OIT, 1998; Jones 1997; Bloss, 1997) with a payback period of 0.5 years (IAC, 1999). This measure offers a quick payback but is often not implemented because maintenance and energy costs are separately budgeted. Some systems already use this practice. An audit of the Flying J Refinery in North Salt Lake, Utah (U.S.) identified annual savings of \$147,000 by repairing leaking steam traps (Brueske et al., 2002).

**Monitor Steam Traps Automatically.** Attaching automated monitors to steam traps in conjunction with a maintenance program can save even more energy, without significant added cost. This system is an improvement over steam trap maintenance alone, because it gives quicker notice of steam trap malfunctioning or failure. Using automatic monitoring is estimated to save an additional 5% over steam trap maintenance, with a payback of 1 year<sup>5</sup> (Johnston, 1995; Jones, 1997). Systems that are able to implement steam trap maintenance are also likely to be able to implement automatic monitoring. On average, 50% of systems can still implement automatic monitoring of steam traps.

**Repair Leaks.** As with steam traps, the distribution pipes themselves often have leaks that go unnoticed without a program of regular inspection and maintenance. In addition to saving up to 3% of energy costs for steam production, having such a program can reduce the likelihood of having to repair major leaks (U.S. DOE-OIT, 1998). On average, leak repair has a payback period of 0.4 years (IAC, 1999).

**Recover Flash Steam.** When a steam trap purges condensate from a pressurized steam distribution system to ambient pressure, flash steam is produced. This steam can be used

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<sup>5</sup> Calculated based on a UK payback of 0.75 years. The U.S. payback is longer because energy prices in the U.S. are lower, while capital costs are similar.

for space heating or feed water preheating (Johnston, 1995). The potential for this measure is extremely site dependent, as it is unlikely that a producer will want to build an entirely new system of pipes to transport this low-grade steam to places where it can be used, unless it can be used close to the steam traps. Hence, the savings are strongly site dependent. Many sites will use multi-pressure steam systems. In this case, flash steam formed from high-pressure condensate can be routed to reduced pressure systems.

Vulcan Chemicals in Geismar, Louisiana (U.S.) implemented a flash steam recovery project at one of the processes at their chemical plant. The project recovered 100% of the flash steam and resulted in net energy savings of 2.8% (Bronhold, 2000).

**Return Condensate.** Reusing the hot condensate in the boiler saves energy and reduces the need for treated boiler feed water. The substantial savings in energy costs and purchased chemicals costs makes building a return piping system attractive. Care has to be taken to design the recovery system to reduce efficiency losses (van de Ruit, 2000). Maximum energy savings are estimated at 10% (U.S. DOE-OIT, 1998) with a payback of 1.1 years (IAC, 1999) for those sites without or with insufficient condensate return. An additional benefit of condensate recovery is the reduction of the blowdown flow rate because boiler feedwater quality has been increased.

#### *Heat Exchangers and Process Integration*

Heating and cooling are operations found throughout the refinery. Within a single process, multiple streams are heated and cooled multiple times. Optimal use and design of heat exchangers is a key area for energy efficiency improvement.

**Heat Transfer– Fouling.** Heat exchangers are used throughout the refinery to recover heat from processes and transfer heat to the process flows. Next to efficient integration of heat flows throughout the refinery (see process integration below), the efficient operation of heat exchangers is a major area of interest. In a complex refinery, most processes occur under high temperature and pressure conditions; the management and optimization of heat transfer among processes is therefore crucial to increasing overall energy efficiency. Fouling, a deposit buildup in units and piping that impedes heat transfer, requires the combustion of additional fuel. For example, the processing of many heavy crude oils in the United States increases the likelihood of localized coke deposits in the heating furnaces, thereby reducing furnace efficiency and creating potential equipment failure. The problem of fouling increases with increased processing of heavier crudes.

Fouling is the effect of several process variables and heat exchanger design. Fouling may follow the combination of different mechanisms (Bott, 2001). Several methods of investigation have been underway to attempt to reduce fouling including the use of sensors to detect early fouling, physical and chemical methods to create high temperature coatings (without equipment modification), the use of ultrasound, as well as the improved long term design and operation of facilities. Worldwide research in fouling reduction and mitigation is continuing (Polley and Pugh, 2002; Polley et al. 2002) by focusing on understanding the principles of fouling and redesign of heat exchangers and reactors.

Currently, various methods to reduce fouling focus on process control, temperature control, regular maintenance and cleaning of the heat exchangers (either mechanically or chemically) and retrofit of reactor tubes (Barletta, 1998).

A study of European refineries identified overall energy savings of 0.7% by cleaning the heat exchanger tubes of the CDU and other furnaces with an estimated payback period of 0.7 years.

Fouling was identified as a major energy loss in an audit of the Equilon refinery in Martinez, California (U.S., now owned by Shell). Regular cleaning of heat exchangers and maintenance of insulation would result in estimated annual savings of over \$14 million at a total expenditure of \$9.85 million (U.S. DOE-OIT, 2002a). Hence, the simple payback period is around 8 months.

**Fouling - CDU.** Fouling is an important factor for efficiency losses in the CDU, and within the CDU, the crude preheater is especially susceptible to fouling (Barletta, 1998). Initial analysis on fouling effects of a 100,000 bbl/day crude distillation unit found an additional heating load of 13.0 MJ/barrel processes (Panchal and Huangfu, 2000). Reducing this additional heating load could result in significant energy savings.

**Process Integration** or pinch technology refers to the exploitation of potential synergies that are inherent in any system that consists of multiple components working together. In plants that have multiple heating and cooling demands, the use of process integration techniques may significantly improve efficiencies.

Developed in the early 1970s, it is now an established methodology for continuous processes (Linnhoff, 1992; CADDET, 1993). The methodology involves the linking of hot and cold streams in a process in a thermodynamic optimal way (i.e., not over the so-called 'pinch'). Process integration is the art of ensuring that the components are well suited and matched in terms of size, function and capability. Pinch analysis takes a systematic approach to identifying and correcting the performance limiting constraint (or pinch) in any manufacturing process (Kumana, 2000a). It was developed originally in the late 1970s at the University of Manchester in England and other places (Linnhoff, 1993) in response to the "energy crisis" of the 1970s and the need to reduce steam and fuel consumption in oil refineries and chemical plants by optimizing the design of heat exchanger networks. Since then, the pinch approach has been extended to resource conservation in general, whether the resource is capital, time, labor, electrical power, water or a specific chemical species such as hydrogen.

The critical innovation in applying pinch analysis was the development of "composite curves" for heating and cooling, which represent the overall thermal energy demand and availability profiles for the process as a whole. When these two curves are drawn on a temperature-enthalpy graph, they reveal the location of the process pinch (the point of closest temperature approach), and the minimum thermodynamic heating and cooling requirements. These are called the energy targets. The methodology involves first identifying the targets and then following a systematic procedure for designing heat

exchanger networks to achieve these targets. The optimum approach temperature at the pinch is determined by balancing the capital-energy tradeoffs to achieve the desired payback. The procedure applies equally well to new designs as well as to retrofits of existing plants.

The analytical approach to this analysis has been well documented in the literature (Kumana, 2000b; Smith, 1995; Shenoy, 1994). Energy savings potential using pinch analysis far exceeds that from well-known conventional techniques such as heat recovery from boiler flue gas, insulation and steam trap management.

Pinch analysis, and competing process integration tools, have been developed further in the past several years. The most important developments in the energy area are the inclusion of alternative heat recovery processes such as heat pumps and heat transformers, as well as the development of pinch analysis for batch processes (or in other words bringing in time as a factor in the analysis of heat integration). Furthermore, pinch analysis should be used in the design of new processes and plants, as process integration goes beyond optimization of heat exchanger networks (Hallale, 2001). Even in new designs additional opportunities for energy efficiency improvement can be identified. Pinch analysis has also been extended to the areas of water recovery and efficiency, and hydrogen recovery (See also Hydrogen pinch, below). Water used to be seen as a low-cost resource to the refinery, and was used inefficiently. However, as the standards and costs for waste water treatment increase and the costs for feedwater makeup increase, the industry has become more aware of water costs. In addition, large amounts of energy are used to process and move water through the refinery. Hence, water savings will lead to additional energy savings. Water pinch can be used to develop targets for minimal water use by reusing water in an efficient manner. Optimization software has been developed to optimize investment and operation costs for water systems in a plant (Hallale, 2001). New tools have been developed to optimize water and energy use in an integrated manner (Wu, 2000). Water pinch has until now mainly been used in the food industry, reporting reductions in water intake of up to 50% (Polley and Polley, 2000). Dunn and Bush (2001) report the use of water pinch for optimization of water use in chemical plants operated by Solutia, resulting in sufficient water use reductions to allow expansion of production and of the site with no net increase in water use. No water pinch analysis studies specific for the petroleum refining industry were found. Major oil companies, e.g., BP and Exxon, have applied hydrogen pinch analysis for selected refineries.

**Total Site Pinch Analysis** has been applied by over 40 refineries around the world to find optimum site-wide utility levels by integrating heating and cooling demands of various processes, and by allowing the integration of CHP into the analysis. Process integration analysis of existing refineries and processes should be performed regularly, as continuous changes in product mix, mass flows, and applied processes can provide new or improved opportunities for energy and resource efficiency.

Major refineries that have applied total site pinch analysis are: Amoco, Agip (Italy), BP, Chevron, Exxon (in the Netherlands and UK), and Shell (several European plants). Typical savings identified in these site-wide analyses are around 20-30%, although the

economic potential was found to be limited to 10-15% (Linnhoff-March, 2000). A total-site analysis was performed of a European oil refinery in the late 1990s. The Solomon's EII of the refinery was within the top quartile. The refinery operates 16 processes including a CDU, VDU, FCC, reformer, coker and hydrotreaters. A study of the opportunities offered by individual process optimization of the CDU, VDU, FCC, coker, and two hydrotreaters found a reduction in site EII of 7.5%. A total-site analysis including the cogeneration unit identified a potential reduction of 16% (Linnhoff-March, 2000). Identified opportunities including the conversion of a back-pressure turbine to a condensing turbine, and improved integration of the medium-pressure and low-pressure steam networks. The economically attractive projects would result in savings of approximately 12-13%.

Site analyses by chemical producer Solutia identified annual savings of \$3.9 million (of which 2.7 with a low payback) at their Decatur plant, 0.9M\$/year at the Anniston site and 3.6 M\$/year at the Pensacola site (Dunn and Bush, 2001).

**Process Integration - Hot Rundown** – Typically process integration studies focus on the integration of steam flows within processes and between processes. Sometimes it is possible to improve the efficiency by retaining the heat in intermediate process flows from one unit to another unit. This reduces the need for cooling or quenching in one unit and reheating in the other unit. Such an integration of two processes can be achieved through automated process controls linking the process flows between both processes. An audit of the Equilon refinery in Martinez, California (U.S.), identified annual savings of \$4.3 million (U.S. DOE-OIT, 2002a). However, the audit results did not include an assessment of investments and payback.

**Process Integration - CDU.** The CDU process all the incoming crude and, hence, is a major energy user in all refinery layouts (except for those refineries that receive intermediates by pipeline from other refineries). In fact, it is estimated that the CDU is the largest energy consuming process of all refinery processes (Worrell and Galitsky, 2005). Energy use and products of the CDU depend on the type of crude processed. New CDUs are supplied by a number of global companies such as ABB Lummus, Kellogg Brown & Root, Shell Global Solutions, Stone & Webster, Technip/Elf, and UOP. An overview of available process designs is published as Hydrocarbon Processing's Refining Processes (HCP, 2000).

Process integration is especially important in the CDU, as it is a large energy consumer processing all incoming crude oil. Older process integration studies show reductions in fuel use between 10 and 19% for the CDU (Clayton, 1986; Sunden, 1988; Lee, 1989) with payback periods less than 2 years. An interesting opportunity is the integration of the CDU and VDU, which can lead to fuel savings from 10-20% (Clayton, 1986; Petrick and Pellegrino, 1999) compared to non-integrated units, at relatively short paybacks. The actual payback period will depend heavily on the layout of the refinery, needed changes in the heat exchanger network and the fuel prices.

The CDU at BP's Kwinana (Australia) refinery was already performing well with limited opportunities for further economic process integration. An analysis of the CDU identified a significant potential for reduction but with a payback of around 6 years. However, integration with the residue cracking unit offered significant opportunities to reduce the combined heating demand by 35-40% with a simple payback period of 1.6 years (Querzoli, 2002).

**Process Integration - Fluid Catalytic Cracker (FCC).** The FCC is a considerable energy consumer in a modern refiner, equal to greater than 6%. There are a large number of FCC designs in use, and many were originally built in the 1970s. Today, more energy efficient designs are being marketed by a number of suppliers. The designs vary in reactor design, type of catalyst used and degree of heat integration. An overview of available process designs is published as Hydrocarbon Processing's Refining Processes (HCP, 2000). The major suppliers are ABB Lummus, Kellogg Brown & Root, Shell Global Solutions, Stone & Webster, and UOP. The optimal design will be based on the type of feed processed and desired product mix and quality. When selecting a new FCC, process energy efficiency should be an integral part of the selection process.

In existing FCC units, energy efficiency can be improved by increasing heat integration and recovery, process flow scheme changes, and power recovery. A FCC has a multitude of flows that need to be heated (sink) and cooled (source). The better the integration of the heat sinks and sources, the lower the energy consumption of an FCC will be. Older FCC designs often do not have an optimized heat exchange setup, which may especially lead to wasted low-temperature heat, which could be used to preheat boiler feed water or cold feed. However, by better integrating the sources and sinks, following the principles of pinch technology (see above), through improved combinations of temperature levels and heating/cooling loads energy use is lowered. Various authors have reported on the application of pinch analysis and process optimization of FCCs (Hall et al., 1995; Golden and Fulton, 2000). The appropriate combination will depend on the feed processed and output produced. Furthermore, economics for the installation of heat exchangers may determine the need for less efficient combinations.

Al-Riyami et al. (2001) studied the opportunities for process integration of a FCC unit in a refinery in Romania. The FCC unit was originally built by UOP and is used to convert vacuum gas oil and atmospheric gas oil. Several design options were identified to reduce utility consumption. The study of the FCC identified a reduction in utilities of 27% at a payback of 19 months. However, the calculation for the payback period only includes the heat exchangers, and, depending on the design of the FCC and layout of the plant, the payback period may be longer for other plant designs.

At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The audit identified additional opportunities for heat recovery in the FCC by installing a waste heat boiler before the electrostatic precipitator, resulting in savings of \$210,000/year at a payback of 2 years (Venkatesan and Iordanova, 2003).

**Process Integration - FCC-Process Flow Changes.** The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or changing the number of pumparounds can improve energy efficiency of the FCC, as it allows increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions to enhance product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC-unit with appropriate modifications of equipment and operating conditions can increase the yield of high octane gasoline and alkylate from 3% to 7% per barrel of crude oil. This would result in energy savings.

**Process Integration - Reformer.** At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The audit identified opportunities to improve the performance of the economizer in the waste heat boilers of two reformer furnaces. The changes would result in annual savings of \$140,000 in each reformer at a payback period of 2 years (Venkatesan and Iordanova, 2003).

**Process Integration - Coker.** A simulation and optimization of a coker of Jinling Petrochemical Corp.'s Nanjing refinery (China) in 1999 identified a more efficient way to integrate the heat flows in the process. By changing the diesel pumparound, they achieved an energy cost reduction of \$100,000/year (Zhang, 2001).

### *Process Heaters*

Over 60% of all fuel used in the refinery is used in furnaces and boilers. The average thermal efficiency of furnaces is estimated at 75-90% (Petrick and Pellegrino, 1999). Accounting for unavoidable heat losses and dewpoint considerations, the theoretical maximum efficiency is around 92% (HHV) (Petrick and Pellegrino, 1999). This suggests that on average a 10% improvement in energy efficiency can be achieved in furnace and burner design.

The efficiency of heaters can be improved by improving heat transfer characteristics, enhancing flame luminosity, installing recuperators or air-preheaters, and improved controls. New burner designs aim at improved mixing of fuel and air and more efficient heat transfer. Many different concepts are developed to achieve these goals, including lean-premix burners (Seebold et al., 2001), swirl burners (Cheng, 1999), pulsating burners (Petrick and Pellegrino, 1999) and rotary burners (U.S. DOE-OIT, 2002c). At the same time, furnace and burner design has to address safety and environmental concerns. The most notable is the reduction of NO<sub>x</sub> emissions. Improved NO<sub>x</sub> control will be necessary in almost all refineries to meet air quality standards, especially as many refineries are located in non-attainment areas.

**Maintenance.** Regular maintenance of burners, draft control and heat exchangers is essential to maintain safe and energy efficient operation of a process heater.

**Draft Control.** Badly maintained process heaters may use excess air. This reduces the efficiency of the burners. Excess air should be limited to 2-3% oxygen to ensure complete combustion.

Valero's Houston, Texas (U.S.) refinery has installed new control systems to reduce excess combustion air at the three furnaces of the CDU. The control system allows running the furnace with 1% excess oxygen instead of the regular 3 to 4%. The system has not only reduced energy use by 3 to 6% but also reduced NO<sub>x</sub> emissions by 10 to 25%, and enhanced the safety of the heater (Valero, 2003). The energy savings result in an estimated cost savings of \$340,000. Similar systems will be introduced in 94 process heaters at the 12 Valero U.S. refineries, and is expected to result in savings of \$8.8 million/year.

An audit of the Paramount Petroleum Corp.'s asphalt refinery in Paramount, California (U.S.) identified excess draft air in six process heaters. Regular maintenance (twice per year) can reduce the excess draft air and would result in annual savings of over \$290,000 (or nearly 100,000 GJ/year). The measure has a simple payback period of 2 months (U.S. DOE-OIT, 2003a).

An audit co-funded by U.S. Department of Energy, of the Equilon refinery (now owned by Shell) in Martinez, California (U.S.) found that reduction of excess combustion and draft air would result in annual savings of almost \$12 million (U.S. DOE-OIT, 2002a). A similar audit of the Flying J Refinery at North Salt Lake, Utah (U.S.) found savings of \$100,000/year through oxygen control of the flue gases to control the air intake of the furnaces (Brueske et al., 2002).

**Air Preheating** is an efficient way of improving the efficiency and increasing the capacity of a process heater. The flue gases of the furnace are used to preheat the combustion air. Every 1.7°C (35°F) drop in the exit flue gas temperature increases the thermal efficiency of the furnace by 1% (Garg, 1998). Typical fuel savings range between 8 and 18%, and is typically economically attractive if the flue gas temperature is higher than 340°C (650°F) and the heater size is 50 GJ/hr or more (Garg, 1998). The optimum flue gas temperature is also determined by the sulfur content of the flue gases to reduce corrosion. When adding a preheater, the burner needs to be rerated for optimum efficiency. The typical payback period for combustion air preheating in a refinery is estimated at 2.5 years. However, the costs may vary strongly depending on the layout of the refinery and furnace construction.

**VDU.** At a refinery in the United Kingdom, a site analysis of energy efficiency opportunities was conducted. The refinery operated 3 VDUs of which one still used natural draught and had no heat recovery installed. By installing a combustion air preheater, using the hot flue gas, and an additional FD fan, the temperature of the flue gas was reduced to 240°C (470°F). This led to energy cost savings of \$109,000/year with a payback period of 2.2 years (Venkatesan and Iordanova, 2003).



**New Burners.** In many areas, new air quality regulation will demand refineries to reduce NO<sub>x</sub> and VOC emissions from furnaces and boilers. Instead of installing expensive selective catalytic reduction (SCR) flue gas treatment plants, new burner technology reduces emissions dramatically. This will result in cost savings as well as help to decrease electricity costs for the SCR.

ChevronTexaco, in collaboration with John Zink Co., developed new low-NO<sub>x</sub> burners for refinery applications based on the lean premix concept. The burners help to reduce NO<sub>x</sub> emissions from 180 ppm to below 20 ppm. The burners have been installed in a CDU, VDU, and a reformer at ChevronTexaco's Richmond, California (U.S.) refinery, without taking the furnace out of production. The burner was also applied to retrofit a steam boiler. The installation of the burners in a reforming furnace reduced emissions by over 90%, while eliminating the need for an SCR. This saved the refinery \$10 million in capital costs and \$1.5 million in annual operating costs of the SCR (Seebold et al., 2001). The operating costs include the saved electricity costs for operating compressors and fans for the SCR. The operators had to be retrained to operate the new burners as some of the operation characteristics had changed.

### *Distillation*

Distillation is one of the most energy intensive operations in the petroleum refinery. Distillation is used throughout the refinery to separate process products, either from the CDU/VDU or from conversion processes. The incoming flow is heated, after which the products are separated on the basis of boiling points. Heat is provided by process heaters (see Process Heaters Section, above) and/or by steam (see Steam Generation and Distribution Section, above). Energy efficiency opportunities exist in the heating side and by optimizing the distillation column.

**Operation Procedures.** The optimization of the reflux ratio of the distillation column can produce significant energy savings. The efficiency of a distillation column is determined by the characteristics of the feed. If the characteristics of the feed have changed over time or compared to the design conditions, operational efficiency can be improved. If operational conditions have changed, calculations to derive new optimal operational procedures should be done. The design reflux should be compared with the actual ratios controlled by each shift operator. Steam and/or fuel intensity can be compared to the reflux ratio, product purity, etc. and compared with calculated and design performance on a daily basis to improve the efficiency.

**Check Product Purity.** Many companies tend to excessively purify products and sometimes with good reason. However, purifying to 98% when 95% is acceptable is not necessary. In this case, the reflux rate should be decreased in small increments until the desired purity is obtained. This will decrease the reboiler duties. This change will require no or very low investments (Saxena, 1997).

**Seasonal Operating Pressure Adjustments.** For plants that are in locations that experience winter climates, the operating pressure can be reduced according to a decrease

in cooling water temperatures (Saxena, 1997). However, this may not apply to the VDU or other separation processes operating under vacuum. These operational changes will generally not require any investment.

**Reducing Reboiler Duty.** Reboilers consume a large part of total refinery energy use as part of the distillation process. By using chilled water, the reboiler duty, in principal, can be lowered by reducing the overhead condenser temperature. A study of using chilled water in a 100,000 bbl/day CDU has led to an estimated fuel saving of 12.8 GJ/hr (12.2 MBtu/hr) for a 5% increase in cooling duty (2.6 GJ/hr or 2.5 MBtu/hr) (Petrick and Pellegrino, 1999), assuming the use of chilled water with a temperature of 10°C (50°F). The payback period was estimated at 1 to 2 years, however, excluding the investments to change the tray design in the distillation tower. This technology is not yet proven in a commercial application. This technology can also be applied in other distillation processes.

**Upgrading Column Internals.** Damaged or worn internals can result in increased operation costs. As the internals become damaged, efficiency decreases and pressure drops rise. This causes the column to run at a higher reflux rate over time. With an increased reflux rate, energy costs will increase accordingly. Replacing the trays with new ones or adding a high performance packing can have the column operating like the day it was brought online. If operating conditions have seriously deviated from designed operating conditions, the investment may have a relative short payback.

New tray designs are marketed and developed for many different applications. When replacing the trays, it will often be worthwhile to consider new efficient tray designs. New tray designs can result in enhanced separation efficiency and decrease pressure drop. This will result in reduced energy consumption. When considering new tray designs, the number of trays should be optimized.

**Stripper Optimization.** Steam is injected into the process stream in strippers. Steam strippers are used in various processes, and especially the CDU is a large user. The strip steam temperature can be too high, and the strip steam use may be too high. Optimization of these parameters can reduce energy use considerably. This optimization can be part of a process integration (or pinch) analysis for the particular unit (see Heat Exchangers Pinch Integration Section, above).

**Progressive Crude Distillation.** Technip and Elf (France) developed an energy efficient design for a crude distillation unit, by redesigning the crude preheater and the distillation column. The crude preheat train was separated in several steps to recover fractions at different temperatures. The distillation tower was re-designed to work at low pressure and the outputs were changed to link to the other processes in the refinery and product mix of the refinery. The design resulted in reduced fuel consumption and better heat integration (reducing the net steam production of the CDU). Technip claims up to a 35% reduction in fuel use when compared to a conventional CDU (Technip, 2000). This technology has been applied in the new refinery constructed at Leuna (Germany) in 1997 and is being used for another new refinery under construction in Europe. Because of the

changes in CDU-output and needed changes in intermediate flows, progressive crude distillation is especially suited for new construction or large crude distillation expansion projects.

**Dividing-Wall Distillation.** The concept of dividing-wall columns originates from 1949, but it was not until recently that practical and commercial designs became possible. Process integration studies and other development work since the early 1990's have resulted in the first commercial application of the dividing-wall distillation column (Hallale, 2001). A dividing-wall column integrates two conventional distillation columns into one column, increasing heat transfer. Dividing-wall columns (DWC) can save up to 30% in energy costs, while providing lower capital costs, compared to conventional columns (Schultz et al., 2002). Various companies (Kellog Brown & Root, Krupp Uhde, Linde, Sumitomo, and UOP) have developed DWC-concepts for the separation of products. BASF in Germany pioneered the DWC and operates the largest number of DWCs in the world in their chemical plants. In petroleum refining BP, Veba Oel (Germany), Sasol (South Africa) and Chevron operate DWCs. Current DWC-applications are limited to benzene removal from gasoline or the separation of lighter fractions in gasoline production. Further development of DWC for the major distillation processes in the petroleum refining industry is necessary.

**Membranes** may offer future alternatives to distillation. Membranes have started to enter the refinery for hydrogen recovery (see Hydrogen Management and Recovery Section), but are also being developed for other separations. An extensive study funded by the U.S. Department of Energy focused on membranes for different separations (gas/gas, fluid/fluid) and studied current state-of-the-art and the potential applications in petroleum refining (Dorgan et al., 2003). Dorgan et al. (2003) conclude that membrane technology will definitely enter the refinery, although further research is needed to develop appropriate membrane materials that can withstand the environment found in petroleum refining processes. Also, membrane technology should be evaluated as an integrated part of the specific process for which it's being implemented to warrant the full energy savings potential.

**Reactive Distillation.** By combining the chemical reaction and separation in one reactor, capital costs are reduced and energy efficiency is improved through better integration of these process steps. Reactive distillation offers a promising alternative to conventional reaction-distillation schemes (Sundmacher and Kienle, 2003). Furthermore, active removal of reaction products can help shift the equilibrium of the reaction and improve the conversion efficiency. Reactive distillation has mainly been used in acetate technology (e.g. MTBE production) (Moritz and Gorak, 2002). Various research institutes and technology developers aim at developing new applications of reactive distillation. In the U.S., researchers developed a reactive distillation process for isomerization to produce clean high-octane isomerate (U.S. DOE-OIT, 2001b). In Europe, a collaborative project of suppliers and universities aims to improve understanding of reactive distillation and develop simulation tools to design new applications. Other new developments include the use of monolithic structures that contain the catalysts (Babbich and Moulijn, 2003),

reducing catalyst loss (Goetze and Bailer, 1999). Monolithic structures result in low pressure drop.

### *Hydrogen Management and Recovery*

Hydrogen is used in the refinery in processes such as hydrocrackers and desulfurization using hydrotreaters. The production of hydrogen is an energy intensive process using naphtha reformers and natural gas-fueled reformers. These processes and other processes also generate gas streams that may contain a certain amount of hydrogen not used in the processes, or generated as by-product of distillation or conversion processes. In addition, different processes have varying quality (purity) demands for the hydrogen feed. Reducing the need for hydrogen make-up will reduce energy use in the reformer and reduce the need for purchased natural gas. Natural gas is an expensive energy input in the refinery process, and especially recently. The major technology developments in hydrogen management within the refinery are hydrogen process integration (or hydrogen cascading) and hydrogen recovery technology (Zagoria and Huycke, 2003). Revamping and retrofitting existing hydrogen networks can increase hydrogen capacity between 3% and 30% (Ratan and Vales, 2002).

**Hydrogen Integration.** Hydrogen network integration and optimization at refineries is a new and important application of pinch analysis (see above). Most hydrogen systems in refineries feature limited integration and pure hydrogen flows are sent from the reformers to the different processes in the refinery. But as the use of hydrogen is increasing, especially in California refineries, the value hydrogen is appreciated more. Using the approach of composition curves used in pinch analysis, the production and uses of hydrogen of a refinery can be made visible. This allows identification of the best matches between different hydrogen sources and uses based on quality of the hydrogen streams. It allows the user to select the appropriate and most cost-effective technology for hydrogen purification. A recent improvement of the analysis technology also accounts for gas pressure, to reduce compression energy needs (Hallale, 2001). The analysis method accounts also for costs of piping, besides the costs for generation, fuel use, and compression power needs. It can be used for new and retrofit studies.

The BP refinery at Carson, California (U.S.), in a project with the California Energy Commission, has executed a hydrogen pinch analysis of the large refinery. Total potential savings of \$4.5 million on operating costs were identified, but the refinery decided to realize a more cost-effective package saving \$3.9 million per year. As part of the plant-wide assessment of the Equilon (Shell) refinery at Martinez, California (U.S.), an analysis of the hydrogen network has been included (U.S. DOE-OIT, 2002a). This has resulted in the identification of large energy savings. One refinery identified savings of \$6 million/year in hydrogen savings without capital projects (Zagoria and Huycke, 2003).

**Hydrogen recovery** is an important technology development area to improve the efficiency of hydrogen recovery, reduce the costs of hydrogen recovery, and increase the purity of the resulting hydrogen flow. Hydrogen can be recovered indirectly by routing low-purity hydrogen streams to the hydrogen plant (Zagoria and Huycke, 2003).

Hydrogen can also be recovered from offgases by routing it to the existing purifier of the hydrogen plant, or by installing additional purifiers to treat the offgases and ventgases. Suitable gas streams for hydrogen recovery are the offgases from the hydrocracker, hydrotreater, coker, or FCC. Not only the hydrogen content determines the suitability, but also the pressure, contaminants (i.e., low on sulfur, chlorine and olefins) and tail end components (C<sub>5</sub>+) (Ratan and Vales, 2002). The characteristics of the source stream will also impact the choice of recovery technology. The cost savings of recovered hydrogen are around 50% of the costs of hydrogen production (Zagoria and Huycke, 2003).

Hydrogen can be recovered using various technologies, of which the most common are pressure swing and thermal swing absorption, cryogenic distillation, and membranes. The choice of separation technology is driven by desired purity, degree of recovery, pressure, and temperature. Various manufacturers supply different types of hydrogen recovery technologies, including Air Products, Air Liquide, and UOP. Membrane technology generally represents the lowest cost option for low product rates, but not necessarily for high flow rates (Zagoria and Huycke, 2003). For high-flow rates, PSA technology is often the conventional technology of choice. PSA is the common technology to separate hydrogen from the reformer product gas. Hundreds of PSA units are used around the world to recover hydrogen from various gas streams. Cryogenic units are favored if other gases, such as LPG, can be recovered from the gas stream as well. Cryogenic units produce a medium purity hydrogen gas stream (up to 96%).

Membranes are an attractive technology for hydrogen recovery in the refinery. If the content of recoverable products is higher than 2-5% (or preferably 10%), recovery may make economic sense (Baker et al., 2000). New membrane applications for the refinery and chemical industries are under development. Membranes for hydrogen recovery from ammonia plants have first been demonstrated about 20 years ago (Baker et al., 2000), and are used in various state-of-the-art plant designs. Refinery offgas flows have a different composition, making different membranes necessary for optimal recovery. Membrane plants have been demonstrated for recovery of hydrogen from hydrocracker offgases. Various suppliers offer membrane technologies for hydrogen recovery in the refining industry, including Air Liquide, Air Products and UOP. Air Liquide and UOP have sold over 100 membrane hydrogen recovery units around the world. Development of low-cost and efficient membranes is an area of research interest to improve cost-effectiveness of hydrogen recovery, and enable the recovery of hydrogen from gas streams with lower concentrations.

At the refinery at Ponca City Oklahoma (U.S., currently owned by ConocoPhillips), a membrane system was installed to recover hydrogen from the waste stream of the hydrotreater, although the energy savings were not quantified (Shaver et al., 1991). Another early study quotes a 6% reduction in hydrogen makeup after installing a membrane hydrogen recovery unit at a hydrocracker (Glazer et al., 1988).

### *Hydrogen Production*

**Reformer – Adiabatic Pre-Reformer.** If there is excess steam available at a plant, a pre-reformer can be installed at the reformer. Adiabatic steam reforming uses a highly active nickel catalyst to reform a hydrocarbon feed, using waste heat (900°F) from the convection section of the reformer. This may result in a production increase of as much as 10% (Abrardo and Khurana, 1995). The Kemira Oy ammonia plant in Rozenburg, the Netherlands, implemented an adiabatic pre-reformer. Energy savings equaled about 4% of the energy consumption at a payback period between 1 and 3 years (Worrell and Blok, 1994). ChevronTexaco included a pre-reformer in the design of the new hydrogen plant for the El Segundo, California refinery (U.S.). The technology can also be used to increase the production capacity at no additional energy cost, or to increase the feed flexibility of the reformer. This is especially attractive if a refinery faces increased hydrogen demand to achieve increased desulfurization needs or switches to heavier crudes. Various suppliers provide pre-reformers including Haldor-Topsoe, Süd-Chemie, and Technip-KTI.

### *Motors*

Electric motors are used throughout the refinery, and represent over 80% of all electricity use in the refinery. The major applications are pumps (60% of all motor use), air compressors (15% of all motor use), fans (9%), and other applications (16%). The following sections discuss opportunities for motors in general, pumps, compressors, and fans. When available, specific examples are listed detailing the refining process to which the measure has been applied and to what success.

Using a “systems approach” that looks at the entire motor system (pumps, compressors, motors, and fans) to optimize supply and demand of energy services often yields the most savings. For example, in pumping, a systems approach analyzes both the supply and demand sides and how they interact, shifting the focus of the analysis from individual components to total system performance. The measures identified below reflect aspects of this system approach including matching speed and load (adjustable speed drives), sizing the system correctly, as well as upgrading system components. However, for optimal savings and performance, the systems approach is recommended. Pumps and compressors are discussed in more detail in their respective sections, below.

**Sizing of Motors.** Motors and pumps that are sized inappropriately result in unnecessary energy losses. Where peak loads can be reduced, motor size can also be reduced. Correcting for motor oversizing saves 1.2% of their electricity consumption (on average for the U.S. industry), and even larger percentages for smaller motors (Xenergy, 1998).

**Higher Efficiency Motors.** High efficiency motors reduce energy losses through improved design, better materials, tighter tolerances, and improved manufacturing techniques. With proper installation, energy efficient motors run cooler and consequently have higher service factors, longer bearing and insulation life and less vibration. Yet, despite these advantages, less than 8% of U.S. industrial facilities address motor efficiency in specifications when purchasing a motor (Tutterow, 1999).

Typically, high efficiency motors are economically justified when exchanging a motor that needs replacement, but are not economically feasible when replacing a motor that is still working (CADDET, 1994). Typically, motors have an annual failure rate varying between 3 and 12% (House et al., 2002). Sometimes though, according to a case study by the Copper Development Association (CDA, 2000), even working motor replacements may be beneficial. The payback for individual motors varies based on size, load factor, and running time. The best savings are achieved on motors running for long hours at high loads. When replacing retiring motors, paybacks are typically less than one year from energy savings alone (LBNL et al., 1998).

To be considered energy efficient in the United States, a motor must meet performance criteria published by the National Electrical Manufacturers Association (NEMA). However, most manufacturers offer lines of motors that significantly exceed the NEMA-defined criteria (U.S. DOE-OIT, 2001d). NEMA and other organizations have created the “Motor Decisions Matter” campaign to market NEMA approved premium efficient motors to industry (NEMA, 2001). Even these premium efficiency motors may have low a payback period. According to data from the CDA, the upgrade to high efficiency motors, as compared to motors that achieve the minimum efficiency as specified by the Energy Policy Act, have paybacks of less than 15 months for 50 hp motors (CDA, 2001). Because of the fast payback, it usually makes sense not only to buy an energy efficient motor but also to buy the most efficient motor available (LBNL, 1998).

Replacing a motor with a high efficiency motor is often a better choice than rewinding a motor. The practice of rewinding motors currently has no quality or efficiency standards. To avoid uncertainties in performance of the motor, a new high efficiency motor can be purchased instead of rewinding one.

**Power Factor.** Inductive loads like transformers, electric motors and HID lighting may cause a low power factor. A low power factor may result in increased power consumption, and hence increased electricity costs. The power factor can be corrected by minimizing idling of electric motors, avoiding operation of equipment over its rated voltage, replacing motors by energy efficient motors (see above) and installing capacitors in the AC circuit to reduce the magnitude of reactive power in the system.

**Voltage Unbalance.** Voltage unbalance degrades the performance and shortens the life of three-phase motors. A voltage unbalance causes a current unbalance, which will result torque pulsations, increased vibration and mechanical stress, increased losses, motor overheating reducing the life of a motor. Voltage unbalances may be caused by faulty operation of power correction equipment, unbalanced transformer bank or open circuit. It is recommended that voltage unbalance at the motor terminals does not exceed 1%. Even a 1% unbalance will reduce motor efficiency at part load operation. If the unbalance would increase to 2.5%, motor efficiency will also decrease at full load operation. For a 100 hp motor operating 8000 hours per year, a correction of the voltage unbalance from 2.5% to 1% will result in electricity savings of 9,500 kWh or almost \$500 at an electricity rate of 5 cts/kWh (U.S. DOE-OIT, 2000b). By regularly monitoring the voltages at the motor terminal and using annual thermographic inspections of motors, voltage

unbalances may be identified. Furthermore, make sure that single-phase loads are evenly distributed and install ground fault indicators. Another indicator for a voltage unbalance is a 120 Hz vibration (U.S. DOE-OIT, 2000b).

**Adjustable Speed Drives (ASDs)/ Variable Speed Drives (VSDs).** ASDs better match speed to load requirements for motor operations. Energy use on many centrifugal systems like pumps, fans and compressors is approximately proportional to the cube of the flow rate. Hence, small reductions in flow that are proportional to motor speed can sometimes yield large energy savings. Although they are unlikely to be retrofitted economically, paybacks for installing new ASD motors in new systems or plants can be as low as 1.1 years (Martin et al., 2000). The installation of ASDs improves overall productivity, control and product quality, and reduces wear on equipment, thereby reducing future maintenance costs.

**Variable Voltage Controls (VVCs).** In contrast to ASDs, which have variable flow requirements, VVCs are applicable to variable loads requiring constant speed. The principle of matching supply with demand, however, is the same as for ASDs.

### *Pumps*

In the petroleum refining industry, about 59% of all electricity use in motors is for pumps (Xenergy, 1998). This equals 48% of the total electrical energy in refineries, making pumps the single largest electricity user in a refinery. Pumps are used throughout the entire plant to generate a pressure and move liquids. Studies have shown that over 20% of the energy consumed by these systems could be saved through equipment or control system changes (Xenergy, 1998).

It is important to note that initial costs are only a fraction of the life cycle costs of a pump system. Energy costs, and sometimes operations and maintenance costs, are much more important in the lifetime costs of a pump system. In general, for a pump system with a lifetime of 20 years, the initial capital costs of the pump and motor make up merely 2.5% of the total costs (Best Practice Programme, 1998). Depending on the pump application, energy costs may make up about 95% of the lifetime costs of the pump. Hence, the initial choice of a pump system should be highly dependent on energy cost considerations rather than on initial costs. Optimization of the design of a new pumping system should focus on optimizing the lifecycle costs. Hodgson and Walters (2002) discuss software developed for this purpose (OPSOP) and discuss several case studies in which they show large reductions in energy use and lifetime costs of a complete pumping system. Typically, such an approach will lead to energy savings of 10-17%.

Pumping systems consist of a pump, a driver, pipe installation, and controls (such as adjustable speed drives or throttles) and are a part of the overall motor system, discussed above in the Motors Section. Using a “systems approach” on the entire motor system (pumps, compressors, motors and fans) was also discussed above. In this section, the pumping systems are addressed; for optimal savings and performance, it is recommended that the systems approach incorporating pumps, compressors, motors and fans be used.



There are two main ways to increase pump system efficiency, aside from reducing use. These are reducing the friction in dynamic pump systems (not applicable to static or "lifting" systems) or adjusting the system so that it draws closer to the best efficiency point (BEP) on the pump curve (Hovstadius, 2002). Correct sizing of pipes, surface coating or polishing and adjustable speed drives, for example, may reduce the friction loss, increasing energy efficiency. Correctly sizing the pump and choosing the most efficient pump for the applicable system will push the system closer to the best efficiency point on the pump curve.

**Operations and Maintenance.** Inadequate maintenance at times lowers pump system efficiency, causes pumps to wear out more quickly and increases costs. Better maintenance will reduce these problems and save energy. Proper maintenance includes the following (Hydraulic Institute, 1994; LBNL et al., 1999):

- Replacement of worn impellers, especially in caustic or semi-solid applications.
- Bearing inspection and repair.
- Bearing lubrication replacement, once annually or semiannually.
- Inspection and replacement of packing seals. Allowable leakage from packing seals is usually between two and sixty drops per minute.
- Inspection and replacement of mechanical seals. Allowable leakage is typically one to four drops per minute.
- Wear ring and impeller replacement. Pump efficiency degrades from 1 to 6 points for impellers less than the maximum diameter and with increased wear ring clearances (Hydraulic Institute, 1994).
- Pump/motor alignment check.

For the U.S., typical energy savings for operations and maintenance were estimated to be between 2 and 7% of pumping electricity with a payback period generally of immediate to one year (Xenergy, 1998; U.S. DOE-OIT, 2002d).

**Monitoring.** Monitoring in conjunction with operations and maintenance can be used to detect problems and determine solutions to create a more efficient system. Monitoring can determine clearances that need be adjusted, indicate blockage, impeller damage, inadequate suction, operation outside preferences, clogged or gas-filled pumps or pipes, or worn out pumps. Monitoring should include:

- Wear monitoring
- Vibration analyses
- Pressure and flow monitoring
- Current or power monitoring
- Differential head and temperature rise across the pump (also known as thermodynamic monitoring)
- Distribution system inspection for scaling or contaminant build-up

**Reduce Need.** Holding tanks can be used to equalize the flow over the production cycle, enhancing energy efficiency and potentially reducing the need to add pump capacity. In addition, bypass loops and other unnecessary flows should be eliminated. Energy savings

may be as high as 5-10% for each of these steps (Easton Consultants, 1995). Total head requirements can also be reduced by lowering process static pressure, minimizing elevation rise from suction tank to discharge tank, reducing static elevation change by use of siphons, and lowering spray nozzle velocities.

**More Efficient Pumps.** Pump efficiency may degrade 10 to 25% in its lifetime (Easton Consultants, 1995). Newer pumps are 2 to 5% more efficient. However, industry experts claim the problem is not necessarily the age of the pump but that the process has changed and the pump does not match the operation. Replacing a pump with a new efficient one saves between 2 to 10% of its energy consumption (Elliott, 1994). Higher efficiency motors have also been shown to increase the efficiency of the pump system 2 to 5% (Tutterow, 1999).

A number of pumps are available for specific pressure head and flow rate capacity requirements. Choosing the right pump often saves both in operating costs and in capital costs (of purchasing another pump). For a given duty, selecting a pump that runs at the highest speed suitable for the application will generally result in a more efficient selection as well as the lowest initial cost (Hydraulic Institute and Europump, 2001). Exceptions to this include slurry handling pumps, high specific speed pumps, or where the pump would need a very low minimum net positive suction head at the pump inlet.

**Correct Sizing Of Pump(s) (Matching Pump To Intended Duty).** Pumps that are sized inappropriately result in unnecessary losses. Where peak loads can be reduced, pump size can also be reduced. In a study of U.S. industry, correcting for pump oversizing was estimated to save, on average, 15 to 25% of electricity consumption for pumping (Easton Consultants, 1995). In addition, pump load may be reduced with alternative pump configurations and improved O&M practices.

Where pumps are dramatically oversized, speed can be reduced with gear or belt drives or a slower speed motor. This practice, however, is not common. Paybacks for implementing these solutions are less than one year (U.S. DOE-OIT, 2002b).

The Chevron Refinery in Richmond, California (U.S.), identified two large horsepower secondary pumps at the blending and shipping plant that were inappropriately sized for the intended use and needed throttling when in use. The 400 hp and 700 hp pump were replaced by two 200 hp pumps, and also equipped with adjustable speed drives. The energy consumption was reduced by 4.3 million kWh per year, and resulted in annual savings of \$215,000 (CEC and U.S. DOE-OIT, 2001). With investments of \$300,000 the payback period was 1.4 years.

The Welches Point Pump Station, a medium sized waste water treatment plant located in Milford, Connecticut (U.S.), as a participant in the Department of Energy's Motor Challenge Program, decided to replace one of their system's three identical pumps with one smaller model (Flygt, 2002). They found that the smaller pump could more efficiently handle typical system flows and the remaining two larger pumps could be reserved for peak flows. While the smaller pump needed to run longer to handle the same

total volume, its slower pace and reduced pressure resulted in less friction-related losses and less wear and tear. Substituting the smaller pump has a projected savings of 36,096 kW, more than 20% of the pump system's annual electrical energy consumption. Using this system at each of the city's 36 stations would result in energy savings of over \$100,000. In addition to the energy savings projected, less wear on the system results in less maintenance, less downtime and longer life of the equipment. The station noise is significantly reduced with the smaller pump.

**Use Multiple Pumps.** Often using multiple pumps is the most cost-effective and most energy efficient solution for varying loads, particularly in a static head-dominated system. In a study for U.S. industry, installing parallel systems for highly variable loads was estimated to save, on average, 10 to 50% of the electricity consumption for pumping (Easton Consultants, 1995). Variable speed controls should also be considered for dynamic systems (see below). Parallel pumps also offer redundancy and increased reliability. One case study of a Finnish pulp and paper plant indicated that installing an additional small pump (a "pony pump"), running in parallel to the existing pump used to circulate water from the paper machine into two tanks, reduced the load in the larger pump in all cases except for startup. The energy savings were estimated at \$36,500 (or 486 MWh, 58%) per year giving a payback of 0.5 years (Hydraulic Institute and Europump, 2001).

**Trimming Impeller (or Shaving Sheaves).** If a large differential pressure exists at the operating rate of flow (indicating excessive flow), the impeller (diameter) can be trimmed so that the pump does not develop as much head. In the food processing, paper and petrochemical industries, trimming impellers or lowering gear ratios is estimated to save as much as 75% of the electricity consumption for specific pump applications in the U.S. (Xenergy, 1998).

In one case study in the chemical processing industry, the impeller was reduced from 320 mm to 280 mm, which reduced the power demand by more than 25% (Hydraulic Institute and Europump, 2001). Annual energy demand was reduced by 83 MWh (26%). With an investment cost of \$390 (U.S.), the payback on energy savings alone was 23 days. In addition to energy savings, maintenance costs were reduced, system stability was improved, cavitation was reduced, and excessive vibration and noise were eliminated.

In another case study, Salt Union Ltd., the largest salt producer in the UK trimmed the diameter of a pump impeller at its plant from 320 mm to 280 mm (Best Practice Programme, 1996). After trimming the impeller, they found significant power reductions of 30%, or 197,000 kWh per year, totaling 8,900 GBP. With an investment cost of 260 GBP, and maintenance savings of an additional 3,000 GBP, this resulted in a payback of 8 days (11 days from energy savings alone). In addition to energy and maintenance savings, like the chemical processing plant, cavitation was reduced and excessive vibration and noise were eliminated. With the large decrease in power consumption, the 110 kW motor could be replaced with a 75kW motor, with additional energy savings of about 16,000 kWh per year.

**Controls.** The objective of any control strategy is to shut off unneeded pumps or reduce the load of individual pumps until needed. Remote controls enable pumping systems to be started and stopped more quickly and accurately when needed, and reduce the required labor. In 2000, Cisco Systems, California (U.S.) upgraded the controls on its fountain pumps to turn off the pumps during peak hours (CEC and U.S. DOE-OIT, 2002). The wireless control system was able to control all pumps simultaneously from one location. The project saved \$32,000 and 400,000 kWh annually, representing a savings of 61.5% of the fountain pumps' total energy consumption. With a total cost of \$29,000, the simple payback was 11 months. In addition to energy savings, the project reduced maintenance costs and increased the pumping system's equipment life.

**Adjustable Speed Drives (ASDs).** ASDs better match speed to load requirements for pumps where, just as for motors, energy use is approximately proportional to the cube of the flow rate<sup>6</sup>. Hence, small reductions in flow that are proportional to pump speed may yield large energy savings. New installations may result in short payback periods. In addition, the installation of ASDs improves overall productivity, control, and product quality, and reduces wear on equipment, thereby reducing future maintenance costs.

Similar to being able to adjust load in motor systems, including modulation features with pumps is estimated to save between 20 and 50% of pump energy consumption, at relatively short payback periods, depending on application, pump size, load and load variation (Xenergy, 1998; Best Practice Programme, 1996). As a general rule of thumb, unless the pump curves are exceptionally flat, a 10% regulation in flow should produce pump savings of 20% and 20% regulation should produce savings of 40% (Best Practice Programme, 1996).

The ChevronTexaco refinery in Richmond, California (U.S.) upgraded the feed pumps of the diesel hydrotreater by installing an ASD on a 2,250 hp primary feed pump, as well as changing the operation procedures for a backup pump system. The cost savings amount to \$700,000/year reducing electricity consumption by 12 GWh/year. The pump system retrofit was implemented as part of a demand side management program by the local utility. The refinery did not have to put up any investment capital as it participated in this program (U.S. DOE-OIT, 1999).

Hodgson and Walters (2002) discuss the application of an ASD to replace a throttle of a new to build pumping system. Optimization of the design using a dedicated software package led to the recommendation to install an ASD. This would result in 71% lower energy costs over the lifetime of the system, a 54% reduction in total lifetime costs of the system.

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<sup>6</sup> This equation applies to dynamic systems only. Systems that solely consist of lifting (static head systems) will accrue no benefits (but will often actually become more inefficient) from ASDs because they are independent of flow rate. Similarly, systems with more static head will accrue fewer benefits than systems that are largely dynamic (friction) systems. More careful calculations must be performed to determine actual benefits, if any, for these systems.

**Avoid Throttling Valves.** Throttling valves should always be avoided. Extensive use of throttling valves or bypass loops may be an indication of an oversized pump (Tutterow et al., 2000). Variable speed drives or on off regulated systems always save energy compared to throttling valves (Hovstadius, 2002).

An audit of the 25,000 bpd Flying J Refinery in Salt Lake City (Utah) revealed throttle losses at two 200 hp charge pumps. Minimizing the throttle losses would result in potential energy cost savings of \$39,000 (Brueske et al., 2002). The shutdown of a 250 hp pump when not needed and the minimization of throttle losses would result in additional savings of \$28,000 per year.

**Correct Sizing Of Pipes.** Similar to pumps, undersized pipes also result in unnecessary losses. The pipe work diameter is selected based on the economy of the whole installation, the required lowest flow velocity, and the minimum internal diameter for the application, the maximum flow velocity to minimize erosion in piping and fittings, and plant standard pipe diameters. Increasing the pipe diameter may save energy but must be balanced with costs for pump system components. Easton Consultants (1995) and others in the pulp and paper industry (Xenergy, 1998) estimate for the U.S. industry, retrofitting pipe diameters saves 5 to 20% of their energy consumption, on average. Correct sizing of pipes should be done at the design or system retrofit stages where costs may not be restrictive.

**Replace Belt Drives.** V-belt drives can be replaced with direct couplings to save energy (Xenergy, 1998). In the U.S., savings are estimated to be 1% on average (Xenergy, 1998).

**Precision Castings, Surface Coatings, or Polishing.** The use of castings, coatings, or polishing reduces surface roughness that in turn, increases energy efficiency. It may also help maintain efficiency over time. This measure is more effective on smaller pumps. In one case study in the steel industry, investment in surface coating on the mill supply pumps (350 kW pumps) cost \$1,200 additionally and would be paid back in 5 months by energy savings of \$2,700 (or 36 MWh, 2%) per year (Hydraulic Institute and Europump, 2001). Energy savings for coating pump surfaces are estimated to be 2 to 3% over uncoated pumps (Best Practice Programme, 1998).

**Sealings.** Seal failure accounts for up to 70% of pump failures in many applications (Hydraulic Institute and Europump, 2001). The sealing arrangements on pumps will contribute to the power absorbed. Often the use of gas barrier seals, balanced seals, and no-contacting labyrinth seals optimize pump efficiency.

**Curtailling Leakage through Clearance Reduction.** Internal leakage losses are a result of differential pressure across the clearance between the impeller and the pump casing. The larger the clearance, the greater is the internal leakage causing inefficiencies. The normal clearance in new pumps ranges from 0.35 to 1.0 mm (Hydraulic Institute and Europump, 2001). With wider clearances, the leakage increases almost linearly with the clearance. For example, a clearance of 5 mm decreases the efficiency by 7 to 15% in closed impellers and by 10 to 22% in semi-open impellers. Abrasive liquids and slurries,

even rainwater, can affect the pump efficiency. Using very hard construction materials (such as stainless steel) can reduce the wear rate.

**Dry Vacuum Pumps.** Dry vacuum pumps were introduced in the semiconductor industry in Japan in the mid-1980s, and were introduced in the U.S. chemical industry in the late 1980s. The advantages of a dry vacuum pump are high energy efficiency, increased reliability, and reduced air and water pollution. It is expected that dry vacuum pumps will displace oil-sealed pumps (Ryans and Bays, 2001). Dry pumps have major advantages in applications where contamination is a concern. Due to the higher investment costs of a dry pump, however, it is not expected to make significant inroads in the petroleum refining industry, except for special applications where contamination and pollution control are an important driver.

### *Compressors and Compressed Air*

Compressors consume about 12% of total electricity use in refineries. The major energy users are compressors for furnace combustion air and gas streams in the refinery. Large compressors can be driven by electric motors, steam turbines, or gas turbines. A relatively small part of energy consumption of compressors in refineries is used to generate compressed air. Compressed air is probably the most expensive form of energy available in an industrial plant because of its poor efficiency when it is used. Typically, efficiency from start to end-use is around 10% for compressed air systems (LBNL et al., 1998). In addition, the annual energy cost required to operate compressed air systems is greater than their initial cost. Because of this inefficiency and the sizeable operating costs, if compressed air is used, it should be of minimum quantity for the shortest possible time, constantly monitored and reweighed against alternatives. Because of its limited use in a refinery (but still an inefficient source of energy), the main compressed air measures found in other industries are highlighted. Many opportunities to reduce energy in compressed air systems are not prohibitively expensive; payback periods for some options are extremely short – less than one year.

**Compressed Air - Maintenance.** Inadequate maintenance can lower compression efficiency, increase air leakage or pressure variability and lead to increased operating temperatures, poor moisture control and excessive contamination. Better maintenance will reduce these problems and save energy. Proper maintenance includes the following (LBNL et al., 1998, unless otherwise noted):

- Blocked pipeline filters increase pressure drop. Keep the compressor and intercooling surfaces clean and foul-free by inspecting and periodically cleaning filters. Seek filters with just a 1 psi pressure drop. Payback for filter cleaning is usually under 2 years (Ingersoll-Rand, 2001). Fixing improperly operating filters will also prevent contaminants from entering into equipment and causing them to wear out prematurely. Generally, when pressure drop exceeds 2 to 3 psig replace the particulate and lubricant removal elements. Inspect all elements at least annually. Also, consider adding filters in parallel to decrease air velocity and, therefore, decrease pressure drop. A 2% reduction of annual energy consumption in compressed air systems is projected

for more frequent filter changing (Radgen and Blaustein, 2001). However, one must be careful when using coalescing filters; efficiency drops below 30% of design flow (Scales, 2002).

- Poor motor cooling can increase motor temperature and winding resistance, shortening motor life, in addition to increasing energy consumption. Keep motors and compressors properly lubricated and cleaned. Compressor lubricant should be sampled and analyzed every 1000 hours and checked to make sure it is at the proper level. In addition to energy savings, this can help avoid corrosion and degradation of the system.
- Inspect fans and water pumps for peak performance.
- Inspect drain traps periodically to ensure they are not stuck in either the open or closed position and are clean. Some users leave automatic condensate traps partially open at all times to allow for constant draining. This practice wastes substantial amounts of energy and should never be undertaken. Instead, install simple pressure driven valves. Malfunctioning traps should be cleaned and repaired instead of left open. Some automatic drains do not waste air, such as those that open when condensate is present. According to vendors, inspecting and maintaining drains typically has a payback of less than 2 years (Ingersoll-Rand, 2001).
- Maintain the coolers on the compressor to ensure that the dryer gets the lowest possible inlet temperature (Ingersoll-Rand, 2001).
- Check belts for wear and adjust them. A good rule of thumb is to adjust them every 400 hours of operation.
- Check water-cooling systems for water quality (pH and total dissolved solids), flow and temperature. Clean and replace filters and heat exchangers per manufacturer's specifications.
- Minimize leaks (see also Reduce leaks section, below).
- Specify regulators that close when failed.
- Applications requiring compressed air should be checked for excessive pressure, duration or volume. They should be regulated, either by production line sectioning or by pressure regulators on the equipment itself. Equipment not required to operate at maximum system pressure should use a quality pressure regulator. Poor quality regulators tend to drift and lose more air. Otherwise, the unregulated equipment operates at maximum system pressure at all times and wastes the excess energy. System pressures operating too high also result in shorter equipment life and higher maintenance costs.

**Monitoring.** Proper monitoring (and maintenance) can save a lot of energy and money in compressed air systems. Proper monitoring includes the following (CADDET, 1997):

- Pressure gauges on each receiver or main branch line and differential gauges across dryers, filters, etc.
- Temperature gauges across the compressor and its cooling system to detect fouling and blockages
- Flow meters to measure the quantity of air used
- Dew point temperature gauges to monitor the effectiveness of air dryers
- kWh meters and hours run meters on the compressor drive

- Compressed air distribution systems should be checked when equipment has been reconfigured to be sure no air is flowing to unused equipment or obsolete parts of the compressed air distribution system.
- Check for flow restrictions of any type in a system, such as an obstruction or roughness. These require higher operating pressures than are needed. Pressure rise resulting from resistance to flow increases the drive energy on the compressor by 1% of connected power for every 2 psi of differential (LBNL et al., 1998; Ingersoll-Rand, 2001). Highest pressure drops are usually found at the points of use, including undersized or leaking hoses, tubes, disconnects, filters, regulators, valves, nozzles and lubricators (demand side), as well as air/lubricant separators, aftercoolers, moisture separators, dryers and filters.

**Reduce leaks (in pipes and equipment).** Leaks can be a significant source of wasted energy. A typical plant that has not been well maintained could have a leak rate between 20 to 50% of total compressed air production capacity (Ingersoll Rand, 2001). Leak repair and maintenance can sometimes reduce this number to less than 10%. Overall, a 20% reduction of annual energy consumption in compressed air systems is projected for fixing leaks (Radgen and Blaustein, 2001).

The magnitude of a leak varies with the size of the hole in the pipes or equipment. A compressor operating 2,500 hours per year at 6 bar (87 psi) with a leak diameter of ½ mm is estimated to lose 250 kWh/year; 1 mm to lose 1,100 kWh/year; 2 mm to lose 4,500 kWh/year; and 4 mm to lose 11,250 kWh/year (CADDET, 1997).

In addition to increased energy consumption, leaks can make pneumatic systems/equipment less efficient and adversely affect production, shorten the life of equipment, and lead to additional maintenance requirements and increased unscheduled downtime. Leaks cause an increase in compressor energy and maintenance costs. The most common areas for leaks are couplings, hoses, tubes, fittings, pressure regulators, open condensate traps and shut-off valves, pipe joints, disconnects, and thread sealants. Quick connect fittings always leak and should be avoided. A simple way to detect large leaks is to apply soapy water to suspect areas. The best way to detect leaks is to use an ultrasonic acoustic detector, which can recognize the high frequency hissing sounds associated with air leaks. After identification, leaks should be tracked, repaired, and verified. Leak detection and correction programs should be ongoing efforts.

A retrofit of the compressed air system of a Mobil distribution facility in Vernon, California (U.S.) led to the replacement of a compressor by a new 50 hp compressor and the repair of air leaks in the system. The annual energy savings amounted to \$20,700, and investments were equal to \$23,000, leading to a payback period of just over 1 year (U.S. DOE-OIT, 2003b).

**Reducing the Inlet Air Temperature.** Reducing the inlet air temperature reduces energy used by the compressor. In many plants, it is possible to reduce inlet air temperature to the compressor by taking suction from outside the building. Importing fresh air has paybacks of up to 5 years, depending on the location of the compressor air inlet



(CADDET, 1997). As a rule of thumb, each 3°C will save 1% compressor energy use (CADDET, 1997; Parekh, 2000).

**Maximize Allowable Pressure Dew Point at Air Intake.** Choose the dryer that has the maximum allowable pressure dew point, and best efficiency. A rule of thumb is that desiccant dryers consume 7 to 14% of the total energy of the compressor, whereas refrigerated dryers consume 1 to 2% as much energy as the compressor (Ingersoll Rand, 2001). Consider using a dryer with a floating dew point. Note that where pneumatic lines are exposed to freezing conditions, refrigerated dryers are not an option.

**Controls.** Remembering that the total air requirement is the sum of the average air consumption for pneumatic equipment, not the maximum for each, the objective of any control strategy is to shut off unneeded compressors or delay bringing on additional compressors until needed. All compressors that are on should be running at full load, except for one, which should handle trim duty. Positioning of the control loop is also important; reducing and controlling the system pressure downstream of the primary receiver results in reduced energy consumption of up to 10% or more (LBNL et al., 1998). Radgen and Blaustein (2001) report energy savings for sophisticated controls to be 12% annually. Start/stop, load/unload, throttling, multi-step, variable speed, and network controls are options for compressor controls and described below.

Start/stop (on/off) is the simplest control available and can be applied to small reciprocating or rotary screw compressors. For start/stop controls, the motor driving the compressor is turned on or off in response to the discharge pressure of the machine. They are used for applications with very low duty cycles. Applications with frequent cycling will cause the motor to overheat. Typical payback for start/stop controls is 1 to 2 years (CADDET, 1997).

Load/unload control, or constant speed control, allows the motor to run continuously but unloads the compressor when the discharge pressure is adequate. In most cases, unloaded rotary screw compressors still consume 15 to 35% of full-load power when fully unloaded, while delivering no useful work (LBNL et al., 1998). Hence, load/unload controls may be inefficient and require ample receiver volume.

Modulating or throttling controls allows the output of a compressor to be varied to meet flow requirements by closing down the inlet valve and restricting inlet air to the compressor. Throttling controls are applied to centrifugal and rotary screw compressors. Changing the compressor control to a variable speed control has saved up to 8% per year (CADDET, 1997). Multi-step or part-load controls can operate in two or more partially loaded conditions. Output pressures can be closely controlled without requiring the compressor to start/stop or load/unload.

**Properly Sized Regulators.** Regulators sometimes contribute to the biggest savings in compressed air systems. By properly sizing regulators, compressed air will be saved that is otherwise wasted as excess air. Also, it is advisable to specify pressure regulators that close when failing.

**Sizing Pipe Diameter Correctly.** Inadequate pipe sizing can cause pressure losses, increase leaks, and increase generating costs. Pipes must be sized correctly for optimal performance or resized to fit the current compressor system. Increasing pipe diameter typically reduces annual energy consumption by 3% (Radgen and Blaustein, 2001).

**Heat Recovery For Water Preheating.** As much as 80 to 93% of the electrical energy used by an industrial air compressor is converted into heat. In many cases, a heat recovery unit can recover 50 to 90% of the available thermal energy for space heating, industrial process heating, water heating, makeup air heating, boiler makeup water preheating, industrial drying, industrial cleaning processes, heat pumps, laundries or preheating aspirated air for oil burners (Parekh, 2000). Paybacks are typically less than one year. With large water-cooled compressors, recovery efficiencies of 50 to 60% are typical (LBNL et al., 1998). Implementing this measure recovers up to 20% of the energy used in compressed air systems annually for space heating (Radgen and Blaustein, 2001).

**Adjustable Speed Drives (ASDs).** Implementing adjustable speed drives in rotary compressor systems has saved 15% of the annual compressed air energy consumption (Radgen and Blaustein, 2001). The profitability of installing an ASD on a compressor depends strongly on the load variation of the particular compressor. When there are strong variations in load and/or ambient temperatures there will be large swings in compressor load and efficiency. In those cases, or where electricity prices are relatively high (> 4 cts/kWh) installing an ASD may result in attractive payback periods (Heijkers et al., 2000).

**High Efficiency Motors.** Installing high efficiency motors in compressor systems reduces annual energy consumption by 2%, and has a payback of less than 3 years (Radgen and Blaustein, 2001). For compressor systems, the largest savings in motor performance are typically found in small machines operating less than 10kW (Radgen and Blaustein, 2001).

### *Fans*

Fans are used in boilers, furnaces, cooling towers, and many other applications. As in other motor applications, considerable opportunities exist to upgrade the performance and improve the energy efficiency of fan systems. Efficiencies of fan systems vary considerably across impeller types (Xenergy, 1998). However, the cost-effectiveness of energy efficiency opportunities depends strongly on the characteristics of the individual system.

**Fan Oversizing.** Most of the fans are oversized for the particular application, which can result in efficiency losses of 1-5% (Xenergy, 1998). However, it may often be more cost-effective to control the speed with adjustable speed drives (see below) than to replace the fan system.

**Adjustable Speed Drive (ASD).** Significant energy savings can be achieved by installing adjustable speed drives on fans. Savings may vary between 14 and 49% when retrofitting fans with ASDs (Xenergy, 1998).

An audit of the Paramount Petroleum Corp.'s asphalt refinery in Paramount, California (U.S.) identified the opportunity to install ASDs on six motors in the cooling tower (ranging from 40 hp to 125 hp). The motors are currently operated manually, and are oversized for operation in the winter. If ASDs were installed at all six motors to maintain the cold-water temperature set point electricity savings of 1.2 million kWh/year could be achieved (U.S. DOE-OIT, 2003a). The payback period would be relatively high due to the size of the motors, around 5.8 years. Annual savings were \$46,000.

**High Efficiency Belts (Cog Belts).** Belts make up a variable, but significant portion of the fan system in many plants. It is estimated that about half of the fan systems use standard V-belts, and about two-thirds of these could be replaced by more efficient cog belts (Xenergy, 1998). Standard V-belts tend to stretch, slip, bend and compress, which lead to a loss of efficiency. Replacing standard V-belts with cog belts can save energy and money, even as a retrofit. Cog belts run cooler, last longer, require less maintenance and have an efficiency that is about 2% higher than standard V-belts. Typical payback periods vary from less than one year to three years.

### *Lighting*

Lighting and other utilities represent less than 3% of electricity use in refineries. Still, potential energy efficiency improvement measures exist, and may contribute to an overall energy management strategy. Because of the relative minor importance of lighting and other utilities, this Energy Guide focuses on the most important measures that can be undertaken. Additional information on lighting guidelines and efficient practices is available from the Illuminating Engineering Society of North America ([www.iesna.org](http://www.iesna.org)) and the California Energy Commission (CEC, 2003).

**Lighting Controls.** Lights can be shut off during non-working hours by automatic controls, such as occupancy sensors, which turn off lights when a space becomes unoccupied. Manual controls can also be used in addition to automatic controls to save additional energy in small areas.

**Replace T-12 Tubes by T-8 Tubes or Metal Halides.** T-12 refers to the diameter in 1/8 inch increments (T-12 means 12/8 inch or 3.8 cm diameter tubes). The initial output for T-12 lights is high, but energy consumption is also high. T-12 tubes have poor efficacy, lamp life, lumen depreciation and color rendering index. Because of this, maintenance and energy costs are high. Replacing T-12 lamps with T-8 lamps approximately doubles the efficacy of the former. It is important to remember, however, to work both with the suppliers and manufacturers on the system through each step of the retrofit process. There are a number of T-8 lights and ballasts on the market and the correct combination should be chosen for each system.

Ford North America paint shops retrofitted eleven of their twenty-one paint shops and saw lighting costs reduced by more than 50% (DEQ, 2001). Initial light levels were lower, but because depreciation is less, the maintained light level is equal and the new lamps last two to three times longer. Energy savings totaled 17.5 million kWh annually; operation savings were \$500,000 per year. The Gillette Company manufacturing facility in Santa Monica, California (U.S.) replaced 4300 T-12 lamps with 496 metal halide lamps in addition to replacing 10 manual switches with 10 daylight switches (EPA, 2001). They reduced electricity use by 58% and saved \$128,608 annually. The total project cost was \$176,534, producing a payback of less than 1.5 years.

**Replace Mercury Lights by Metal Halide or High-Pressure Sodium Lights.** In industries where color rendition is critical, metal halide lamps save 50% compared to mercury or fluorescent lamps (Price and Ross, 1989). Where color rendition is not critical, high-pressure sodium lamps offer energy savings of 50 to 60% compared to mercury lamps (Price and Ross, 1989). High-pressure sodium and metal halide lamps also produce less heat, reducing HVAC loads. In addition to energy reductions, the metal halide lights provide better lighting, provide better distribution of light across work surfaces, improve color rendition, and reduce operating costs (GM, 2001).

**Replace Standard Metal Halide HID With High-Intensity Fluorescent Lights.** Traditional HID lighting can be replaced with high-intensity fluorescent lighting. These new systems incorporate high efficiency fluorescent lamps, electronic ballasts, and high-efficacy fixtures that maximize output to the workspace. Advantages of the new system are many: lower energy consumption, lower lumen depreciation over the lifetime of the lamp, better dimming options, faster start-up and restrike capability, better color rendition, higher pupil lumens ratings, and less glare (Martin et al., 2000). High-intensity fluorescent systems yield 50% electricity savings over standard metal halide HID. Dimming controls that are impractical in the metal halide HIDs save significant energy in the new system. Retrofitted systems cost about \$185 per fixture, including installation costs (Martin et al., 2000). In addition to energy savings and better lighting qualities, high-intensity fluorescents may help improve productivity and have reduced maintenance costs.

**Replace Magnetic Ballasts With Electronic Ballasts.** A ballast is a mechanism that regulates the amount of electricity required to start a lighting fixture and maintain a steady output of light. Electronic ballasts save 12 to 25% power over their magnetic predecessors (EPA, 2001). Electronic ballasts have dimming capabilities as well (Eley et al., 1993). If automatic daylight sensing, occupancy sensing and manual dimming are included with the ballasts, savings can be greater than 65% (Turiel et al., 1995).

**Reflectors.** A reflector is a highly polished "mirror-like" component that directs light downward, reducing light loss within a fixture. Reflectors can minimize required wattage effectively.

**Light Emitting Diodes (LEDs) or Radium Lights.** One way to reduce energy costs is simply switching from incandescent lamps to LEDs or radium strips in exit sign lighting. LEDs use about 90% less energy than conventional exit signs (Anaheim Public Utilities, 2001). A 1998 Lighting Research Center survey found that about 80 percent of exit signs being sold use LEDs (LRC, 2001). In addition to exit signs, LEDs are increasingly being used for path marking and emergency way finding systems. Their long life and cool operation allows them to be embedded in plastic materials, which makes them perfect for these applications. Radium strips use no energy at all and can be used similarly.

The Flying J Refinery in North Salt Lake (Utah) replaced exit signs by new LED signs saving about \$1,200/year.

**System Improvements.** By combining several of the lighting measures above, light system improvements can be the most effective and comprehensive way to reduce lighting energy. High frequency ballasts and specular reflectors can be combined with 50% fewer efficient high-frequency fluorescent tubes and produce 90% as much light while saving 50 to 60% of the energy formerly used (Price and Ross, 1989). An office building in Michigan reworked their lighting system using high-efficiency fluorescent ballasts and reduced lighting load by 50% and total building electrical load by nearly 10% (Price and Ross, 1989). Similar results were obtained in a manufacturing facility when replacing fluorescent fixtures with metal halide lamps. Often these system improvements improve lighting as well as decrease energy consumption.

Reducing system voltage may also save energy. One U.S. automobile manufacturer put in reduced voltage HID lights and found a 30% reduction in lighting. Electric City is one of the suppliers of EnergySaver, a unit that attaches to a central panel switch (controllable by computer) and constricts the flow of electricity to fixtures, thereby reducing voltage and saving energy, with an imperceptible loss of light. Bristol Park Industries has patented another lighting voltage controller called the Wattman<sup>®</sup> Lighting Voltage Controller that works with high intensity discharge (HID) and fluorescent lighting systems with similar energy saving results (Bristol Park Industries, 2002).

### *Power Generation*

Most refineries have some form of onsite power generation. In fact, refineries offer an excellent opportunity for energy efficient power generation in the form of combined heat and power production (CHP). CHP provides the opportunity to use internally generated fuels for power production, allowing greater independence of grid operation and even export to the grid. This increases reliability of supply as well as the cost-effectiveness. The cost benefits of power export to the grid will depend on the regulation in the state where the refinery is located. Not all states allow wheeling of power (i.e., sales of power directly to another customer using the grid for transport) while the regulation may also differ with respect to the tariff structure for power sales to the grid operator.

**Combined Heat and Power Generation (CHP).** In the U.S., only about 10% of all steam used in refineries is generated in cogeneration units. The petroleum refining industry is

among the industries with the largest potential for increased application of CHP. In fact, an efficient refinery can be a net exporter of electricity. The potential for exporting electricity is even enlarged with new innovative technologies currently used commercially at selected petroleum refineries (discussed below). The potential for conventional cogeneration installations is estimated at an additional 6,700 MW<sub>e</sub> (Onsite, 2000), of which most in medium to large-scale gas turbine based installations.

Where process heat, steam, or cooling and electricity are used, cogeneration plants are significantly more efficient than standard power plants because they take advantage of what are losses in conventional power plants by utilizing waste heat. In addition, transportation losses are minimized when CHP systems are located at or near the refinery. Third parties have developed CHP for use by refineries. In this scenario, the third party company owns and operates the system for the refinery, which avoids the capital expenditures associated with CHP projects, but gains (part of) the benefits of a more energy efficient system of heat and electricity supply. In fact, about 60% of the cogeneration facilities operated within the refinery industry are operated by third party companies (Onsite, 2000). For example, in 2001 BP's Whiting refinery, Indiana (U.S.) installed a new 525 MW cogeneration unit with a total investment of \$250 million, carried by Primary Energy Inc. Many new cogeneration projects can be financed in this way. Other opportunities consist of joint-ventures between the refinery and an energy generation or operator to construct a cogeneration facility.

Optimization of the operation strategy of CHP units and boilers is an area in which additional savings can be achieved. The development of a dispatch optimization program at the Hellenic Aspropyrgos Refinery (Greece) to meet steam and electricity demand demonstrates the potential energy and cost-savings (Frangopoluos et al., 1996).

For systems requiring cooling, absorption cooling can be combined with CHP to use waste heat to produce cooling power. In refineries, refrigeration and cooling consumes about 5-6% of all electricity. Cogeneration in combination with absorption cooling has been demonstrated for building sites and sites with refrigeration loads. The authors do not know of applications in the petroleum refinery industry.

Innovative gas turbine technologies can make CHP more attractive for sites with large variations in heat demand. **Steam injected gas turbines** (STIG or Cheng cycle) can absorb excess steam, e.g., due to seasonal reduced heating needs, to boost power production by injecting the steam in the turbine. The size of typical STIGs starts around 5 MW<sub>e</sub>, and is currently scaled up to sizes of 125 MW. STIGs have been installed at over 50 sites worldwide, and are found in various industries and applications, especially in Japan and Europe, as well as in the United States. Energy savings and payback period will depend on the local circumstances (e.g., energy patterns, power sales, conditions). In the United States, the Cheng Cycle is marketed by International Power Systems (San Jose, California). The Austrian oil company OMV has considered the use of a STIG to upgrade an existing cogeneration system. The authors do not know of any current commercial applications of STIG in an oil refinery.

Steam turbines are often used as part of the CHP system in a refinery or as stand-alone systems for power generation. The efficiency of the steam turbine is determined by the inlet steam pressure and temperature as well as the outlet pressure. Each turbine is designed for a certain steam inlet pressure and temperature, and operators should make sure that the steam inlet temperature and pressure are optimal. An  $-7.8^{\circ}\text{C}$  decrease in steam inlet temperature will reduce the efficiency of the steam turbine by 1.1% (Patel and Nath, 2000). Similarly, maintaining exhaust vacuum of a condensing turbine or the outlet pressure of a backpressure turbine too high will result in efficiency losses.

Valero's Houston, Texas (U.S.) refinery constructed a 34 MW cogeneration unit in 1990, using two gas turbines and two heat recovery steam generators (boilers). The system supplies all electricity for the refinery and occasionally allows export to the grid. The CHP system has resulted in savings of about \$55,000/day (Valero, 2003).

Even for small refineries, CHP is an attractive option. An audit of the Paramount Petroleum Corp.'s asphalt refinery in Paramount, California (U.S.) identified the opportunity to install CHP at this refinery. The audit identified a CHP unit as the largest energy saving measure in this small refinery. A  $6.5 \text{ MW}_e$  gas turbine CHP unit would result in annual energy savings of \$3.8 million and has a payback period 2.5 years (U.S. DOE-OIT, 2003a). In addition, the CHP unit would reduce the risk of power outages for the refinery. The investment costs assume best available control technology for emission reduction. The installation was installed in 2002.

**Gas Expansion Turbines.** Natural gas is often delivered to a refinery at very high pressures. Gas is transmitted at high pressures, from 200 to 1500 psi. Expansion turbines use the pressure drop when natural gas from high-pressure pipelines is decompressed to generate power or to use in a process heater. An expansion turbine includes both an expansion mechanism and a generator. In an expansion turbine, high-pressure gas is expanded to produce work. Energy is extracted from pressurized gas, which lowers gas pressure and temperature. These turbines have been used for air liquefaction in the chemical industry for several decades. The application of expansion turbines as energy recovery devices started in the early 1980s (SDI, 1982). The technology has much improved since the 1980s and is highly reliable today. A simple expansion turbine consists of an impeller (expander wheel) and a shaft and rotor assembly attached to a generator. Expansion turbines are generally installed in parallel with the regulators that traditionally reduce pressure in gas lines. If flow is too low for efficient generation, or the expansion turbine fails, pressure is reduced in the traditional manner. The drop in pressure in the expansion cycle causes a drop in temperature. While turbines can be built to withstand cold temperatures, most valve and pipeline specifications do not allow temperatures below (-15°C). In addition, gas can become wet at low temperatures, as heavy hydrocarbons in the gas condense. This necessitates heating the gas just before or after expansion. The heating is generally performed with either a CHP unit, or a nearby source of waste heat. Petroleum refineries often have excess low-temperature waste heat, making a refinery an ideal location for a power recovery turbine. Industrial companies and utilities in Europe and Japan have installed expansion turbine projects. However, it is unknown if any petroleum refineries have installed this technology.

In 1994, the Corus integrated steel mill at IJmuiden (the Netherlands) installed a 2 MW power recovery turbine. The mill receives gas at 930 psi, preheats the gas, and expands with the turbine to 120 psi. The maximum turbine flow is 40,000 m<sup>3</sup>/hr while the average capacity is 65%, resulting in an average flow of 25,000 m<sup>3</sup>/hr. The turbine uses cooling water from the hot strip mill of approximately 70°C, to preheat the gas (Lehman and Worrell, 2001). The 2 MW turbine generated roughly 11,000 MWh of electricity in 1994, while the strip mill delivered a maximum of 12,500 MWh of waste heat to the gas flow. Thus, roughly 88% of the maximum heat input to the high-pressure gas emerged as electricity. The cost of the installation was \$2.6 million, and the operation and maintenance costs total \$110,000 per year. With total costs of \$110,000 per year and income of \$710,000 per year from electricity generation (at the 1994 Dutch electricity cost of 6.5 cents per kWh), the payback period for the project is 4.4 years.

**Steam Expansion Turbines.** Steam is generated at high pressures, but often the pressure is reduced to allow the steam to be used by different processes. For example, steam is generated at 120 to 150 psig. This steam then flows through the distribution system within the plant. The pressure is reduced to as low as 10-15 psig for use in different process. Once the heat has been extracted, the condensate is often returned to the steam generating plant. Typically, the pressure reduction is accomplished through a pressure reduction valve (PRV). These valves do not recover the energy embodied in the pressure drop. This energy could be recovered by using a micro scale backpressure steam turbine. Several



manufacturers produce these turbine sets, such as Turbosteam (previously owned by Trigen) and Dresser-Rand.

The potential for application will depend on the particular refinery and steam system used. Applications of this technology have been commercially demonstrated for campus facilities, pulp and paper, food, and lumber industries, but not yet in the petroleum industry. The investments of a typical expansion turbine are estimated at 600 \$/kWe, and operation and maintenance costs at 0.011 \$/kWh.

**High-temperature CHP.** Turbines can be pre-coupled to a crude distillation unit (or other continuously operated processes with an applicable temperature range). The offgases of the gas turbine can be used to supply the heat for the distillation furnace, if the outlet temperature of the turbine is high enough. One option is the so-called 'repowering' option. In this option, the furnace is not modified, but the combustion air fans in the furnace are replaced by a gas turbine. The exhaust gases still contain a considerable amount of oxygen, and can thus be used as combustion air for the furnaces. The gas turbine can deliver up to 20% of the furnace heat. Two of these installations are installed in the Netherlands, with a total capacity of 35 MW<sub>e</sub> at refineries (Worrell et al., 1997). A refinery on the West Coast has installed a 16 MW<sub>e</sub> gas turbine at a reformer (Terrible et al., 1999). The flue gases of the turbine feed to the convection section of the reformer increasing steam generation. The steam is used to power a 20 MW<sub>e</sub> steam turbine.

Another option, with a larger CHP potential and associated energy savings, is "high-temperature CHP". In this case, the flue gases of a CHP plant are used to heat the input of a furnace or to preheat the combustion air. This option requires replacing the existing furnaces. This is due to the fact that the radiative heat transfer from gas turbine exhaust gases is much smaller than from combustion gases, due to their lower temperature (Worrell et al., 1997). A distinction is made between two different types. In the first type, the exhaust heat of a gas turbine is led to a waste heat recovery furnace, in which the process feed is heated. In the second type, the exhaust heat is led to a "waste heat oil heater" in which thermal oil is heated. By means of a heat exchanger, the heat content is transferred to the process feed. In both systems, the remaining heat in the exhaust gases after heating the process feed should be used for lower temperature purposes to achieve a high overall efficiency. The second type is more reliable, due to the fact that a thermal oil buffer can be included. The main difference is that in the first type the process feed is directly heated by exhaust gases, where the second uses thermal oil as an intermediate, leading to larger flexibility. An installation of the first type is installed in Fredericia, Denmark at a Shell refinery. The low temperature remaining heat is used for district heating. R&D has to be aimed at making detailed design studies for specific refineries and the optimization of furnace design, and more demonstration projects have to be carried out.

**Gasification** provides the opportunity for cogeneration using the heavy bottom fraction and refinery residues (Marano, 2003). Because of the increased demand for lighter products and increased use of conversion processes, refineries will have to manage an increasing stream of heavy bottoms and residues. Gasification of the heavy fractions and coke to produce synthesis gas can help to remove efficiently these by-products. The state-of-the-art

gasification processes combine the heavy by-products with oxygen at high temperature in an entrained bed gasifier. Due to the limited oxygen supply, the heavy fractions are gasified to a mixture of carbon monoxide and hydrogen. Sulfur can easily be removed in the form of H<sub>2</sub>S to produce elemental sulfur. The synthesis gas can be used as feedstock for chemical processes. However, the most attractive application seems to be generation of power in an Integrated Gasifier Combined Cycle (IGCC). In this installation the synthesis gas is combusted in a gas turbine (with an adapted combustion chamber to handle the low to medium-BTU gas) generating electricity. The hot fluegases are used to generate steam. The steam can be used onsite or used in a steam turbine to produce additional electricity (i.e., the combined cycle). Cogeneration efficiencies can be up to 75% (lower heating value, LHV) and for power production alone the efficiency is estimated at 38-39% (Marano, 2003).

Entrained bed IGCC technology is originally developed for refinery applications, but is also used for the gasification of coal. Hence, the major gasification technology developers were oil companies like Shell and Texaco. IGCC provides a low-cost opportunity to reduce emissions (SO<sub>x</sub>, NO<sub>x</sub>) when compared to combustion of the residue, and to process the heavy bottoms and residues while producing power and/or feedstocks for the refinery.

IGCC is used by the Shell refinery in Pernis (the Netherlands) to treat residues from the hydrocracker and other residues to generate 110 MW<sub>e</sub> of power and 285 tonnes of hydrogen for the refinery. The IPA Falconara refinery (Italy) uses IGCC to treat visbreaker residue to produce 241 MW<sub>e</sub> of power (Cabooter, 2001). New installations have been announced or are under construction for the refineries at Baytown (ExxonMobil, Texas, U.S.), Deer Park (Shell, Texas, U.S.), Sannazzaro (Agip, Italy), Lake Charles, (Citgo, Louisiana, U.S.) and Bulwer Island (BP, Australia).

The investment costs will vary by capacity and products of the installation. The capital costs of a gasification unit consuming 2,000 tonnes per day of heavy residue would cost about \$229 million of the production of hydrogen and \$347 million for an IGCC unit. The operating cost savings will depend on the costs of power, natural gas, and the costs of heavy residue disposal or processing.

### *Other Opportunities*

#### *Process Changes and Design*

**Desalter.** Alternative designs for desalting include multi-stage desalters and combination of AC and DC fields. These alternative designs may lead to increased efficiency and lower energy consumption (IPPC, 2002).

**Catalytic Reformer - Increased Product Recovery.** Product recovery from a reformer may be limited by the temperature of the distillation to separate the various products. An analysis of a reformer at the Colorado Refinery in Commerce City, Colorado (U.S.) (now operated by Valero) showed increased LPG losses at increased summer temperatures.

The LPG would either be flared or used as fuel gas. By installing a waste heat driven ammonia absorption refrigeration plant, the recovery temperature was lowered, debottlenecking the compressors and the unsaturated light-cycle oil streams (Petrick and Pellegrino, 1999). The heat pump uses a 140°C waste heat stream of the reformer to drive the compressor. The system was installed in 1997 and was supported by the U.S. Department of Energy as a demonstration project. The project resulted in annual savings of 65,000 barrels of LPG. The recovery rate varies with ambient temperature. The liquid product fraction contained a higher percentage of heavier carbon chain (C<sub>5</sub>, C<sub>6</sub>+) products. The payback period is estimated at 1.5 years (Brant et al., 1998).

**Hydrotreater.** Desulfurization is becoming more and more important as probable future regulations will demand a lower sulfur content of fuels. Desulfurization is currently mainly done by hydrotreaters. Hydrotreaters use a considerable amount of energy directly (fuel, steam, electricity) and indirectly (hydrogen). Various alternatives are being developed; the three main routes are advanced hydrotreating (new catalysts, catalytic distillation, processing at mild conditions), reactive adsorption (type of adsorbent used, process design) and oxidative desulfurization (catalyst, process design). Several of these concepts are now being demonstrated at refineries around the world. An advanced hydrotreating process has been developed by a CDTech Company and demonstrated at refineries at Port Arthur, Texas (U.S.) (Babbich and Moulijn, 2003) and Saint John, New Brunswick (Canada) (Gardner et al., 2001). Philips Petroleum developed an absorbent process (S Zorb) which is being demonstrated at the Borger, Texas (U.S.) refinery (Gislason, 2001). Biodesulfurization is being demonstrated at Valero's Krotz Springs, Louisiana (U.S.).

The **S Zorb** process is a sorbent operated in a fluidized bed reactor. Philips Petroleum Co. claims a significant reduction in hydrogen consumption to produce low-sulfur gasoline and diesel (Gislason, 2001). A cursory comparison of the characteristics of the S Zorb process and that of selected hydrotreaters suggests a lower fuel and electricity consumption, but increased water consumption.

**Biodesulfurization** would be a complete breakthrough in process development, while other alternatives to hydrotreaters are under development to desulfurize various refinery products. Biodesulfurization would offer mild processing conditions and reduce the need for hydrogen makeup. Both would lead to high energy-savings in the refinery. Biocatalytic desulfurization (BDS) can potentially offer a low-cost alternative to hydrotreating, reducing capital and operating costs (U.S. DOE-OIT, 2003c). A previous study has developed a design for the process and evaluated the economics (Enchira, 2003). The challenge is to develop bacteria that can reduce the sulfur content of gasoline to a sufficiently low level to meet fuel standards at sufficiently high rate of desulfurization (Borole et al., 2003). Other challenges include biocatalyst stability, oil-water separation and product recovery (Borole et al., 2003). Advantages include reacting at ambient temperatures and pressures and producing non-toxic bioproducts. Biodesulfurization is expected to cost around \$18 million for a 25,000 barrel per day facility in 2015 (a significant savings or a standard desulfurization facility), with a 10 to

15% energy savings and an expected payback period of under 2 years (Martin et al., 2000).

#### *Alternative Production Flows*

**FCC - Process Flow Changes.** The product quality demands and feeds of FCCs may change over time. The process design should remain optimized for this change. Increasing or changing the number of pumparounds can improve energy efficiency of the FCC, as it allows increased heat recovery (Golden and Fulton, 2000). A change in pumparounds may affect the potential combinations of heat sinks and sources.

New design and operational tools enable the optimization of FCC operating conditions to enhance product yields. Petrick and Pellegrino (1999) cite studies that have shown that optimization of the FCC unit with appropriate modifications of equipment and operating conditions can increase the yield of high octane gasoline and alkylate from 3% to 7% per barrel of crude oil. This would result in energy savings.

#### *Other Opportunities*

**Flare Optimization.** Flares are used to dispose safely of combustible gases and to avoid release to the environment of these gases through combustion/oxidation. All refineries operate flares, which, in the majority of refineries are used to burn gases in the case of a system upset. Older flare systems have a pilot flame that is burning continuously. This results in losses of natural gas. Also, this may lead to methane (a powerful greenhouse gas) losses to the environment if the pilot flame is extinguished.

Modern flare pilot designs are more efficient using electronic ignition when the flare is needed, have sensors for flame detection and shut off the fuel gas, reducing methane emissions. These systems can reduce average natural gas use to below 47 MJ/hour. The spark ignition systems use low electrical power, which can be supplied by photovoltaic (solar cell) system, making the whole system independent of an external power supply. Various systems are marketed by a number of suppliers, e.g., John Zink.

Chevron replaced a continuous burning flare by an electronic ignition system at a refinery, which resulted in savings of 177 GJ/year, with a payback off less than 3 years.

**Heated Storage Tanks.** Some storage tanks at the refinery are kept at elevated temperatures to control viscosity of the product stored. Insulation of the tank can reduce the energy losses.

An audit of the Fling J Refinery at North Salt Lake, Utah (U.S.) found that insulating the top of a 80,000 bbl storage tank that is heated to a temperature of 107°F would result in annual savings of \$148,000 (Brueske et al., 2002).

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