Energy Best Practices Guide | October 2020

ETHANOL INDUSTRY

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ETHANOL INDUSTRY ENERGY BEST PRACTICES GUIDEBOOK

FOCUS ON ENERGY®, Wisconsin utilities' statewide program for energy efficiency and renewable energy, helps eligible residents and businesses save energy and money while protecting the environment. Focus on Energy information, resources and financial incentives help to implement energy efficiency and renewable energy projects that otherwise would not be completed.

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Introduction

This guidebook is one of a series of guidebooks developed to highlight industrial energy efficiency best practices in common industrial sectors. The guidebook contains individual best practice descriptions as well as tips for overcoming common barriers encountered during implementation of these practices.

The information provided in the guidebook was identified and screened through site visits to industrial facilities within the targeted sector. This guidebook will be updated as new best practices are identified and screened for applicability. If you have an energy-related best practice for this industry sector that you believe should be included in this guidebook, please reach out to Focus on Energy:

Are you a world-class industrial energy user?

World-class energy users have:

- Received firm commitments from management for plant-wide improvements in energy efficiency and demand reduction
- Aligned their energy using equipment decisions with their corporate goals
- Baselined energy consumption in their plant
- Benchmarked best-practice opportunities
- Defined a quantifiable, affordable energy-reduction goal
- Established a multiyear plan to meet their energy-reduction goals
- Identified the necessary internal and external resources to meet these goals and to provide feedback to continuously improve the plan

If your plant lacks any of these essential ingredients, this guidebook will help you get there.


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ENERGY MANAGEMENT BEST PRACTICES

Any organization can more effectively manage its energy use and costs by adopting a continual improvement approach to energy management, commonly known as an **energy management program** or **Strategic Energy Management (SEM)**. An energy management program provides a systematic and proactive approach to assessing and reducing the energy uses and costs of your organization.

An energy management program is not a single project but an ongoing process. It can be a stand-alone effort devoted exclusively to energy management or adapted to an existing management program such as existing quality assurance or environmental management programs at a facility. The most successful energy-management programs are developed and maintained by a team of individuals from various functions such as maintenance, engineering, production, financing and management.

Energy efficiency is a good investment. Typically, energy cost savings of as much as 15% can be achieved in three years by implementing a systematic energy-management program.

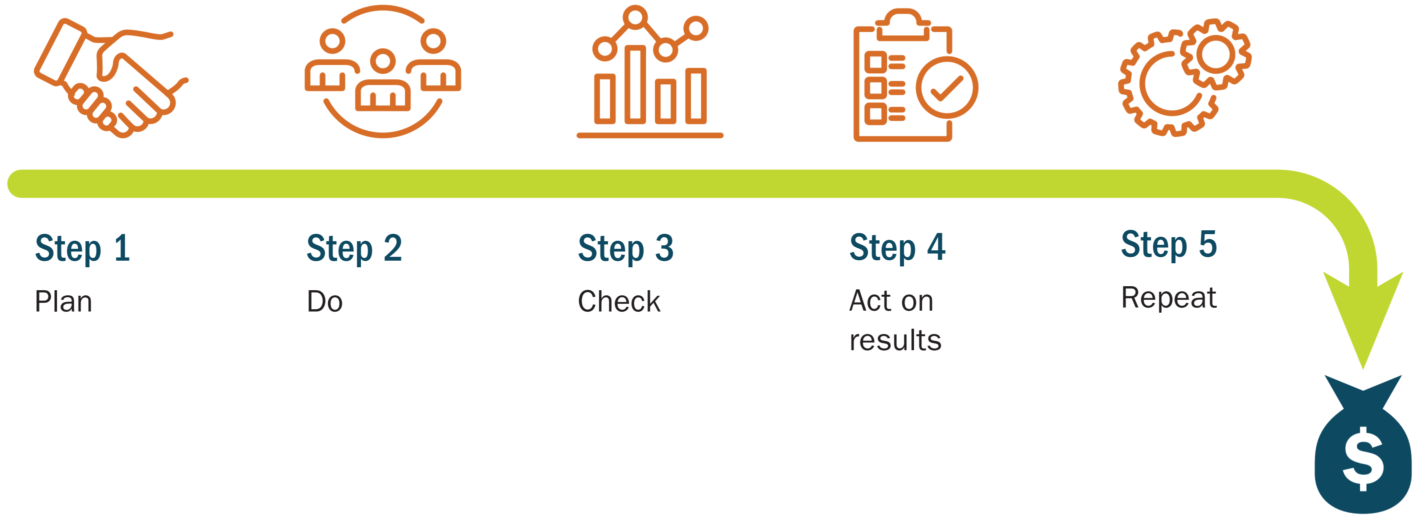
At first glance, creating and implementing an energy-management program may seem to be an overwhelming task, but it doesn't have to be. This chapter outlines simple steps following a Plan, Do, Check, Act continuous improvement cycle for putting the basic elements of energy management in place within your organization.

Steps to getting started

The next several pages outline the steps toward developing and implementing a continuous systematic energy management program. Focus on Energy can assist with completing any of these steps.

There are other well-established energy management protocols to consider including CEE's Strategic Energy Management Minimum Elements (www.cee1.org), the 50001 Ready program by the Department of Energy, or the ISO 50001 standard.

Basic steps in building an energy management program



Step 1
Plan

Step 2
Do

Step 3
Check

Step 4
Act on results

Step 5
Repeat

Step 1 – Plan

Obtain support from plant management

Start with discussing the need for better energy management with the decision makers at your facility. It is critical plant management support these efforts and are willing to allocate resources, both time and money, to achieve those goals and there is accountability for goal achievement.

It is helpful to prepare a business case for plant management. What is your total plant's annual energy spend? What is a reasonable/achievable reduction in annual energy costs because of better energy management? How much staff time can be justified by the estimated reasonable annual energy savings? Focus on Energy can help build this business case.

Establish your energy-performance baseline

Establishing a baseline is critical for monitoring progress to your goals. There are multiple ways to establish baseline energy consumption. The following list of possible baselines is in order of increasing effort but also increasing value.

Basic – Gross energy consumption

Using an average annual or monthly gross energy consumption is the easiest baseline to develop but it is also the least useful. While this approach gives a rough baseline to track future performance against, it does not account for factors which may change your energy consumption based on business demands, like increased production, or reasons out of your control, like weather. This approach is most useful in a plant with stable energy-using processes not impacted by weather.

Better – Production energy intensity metric

By combining energy consumption and production data, you can build a baseline for energy intensity. Building this baseline is done by dividing electricity consumption (kWh) and gas consumption (therms) by total production volume for the same time period. This can be tracked at any interval desired, such as daily or annual. See the second column in the example below.

MONTH	KWH/UNIT	CONSUMPTION (KWH)	PROD UNITS	BILLED DEMAND (KW)	TOTAL ELECTRIC POWER COST
Jan	2.61	2,253,240	862,560	4,953	$103,650
Feb	2.51	2,123,070	845,040	4,953	$97,661
Mar	2.57	2,198,420	855,090	4,953	$101,127
Apr	2.49	2,056,720	826,640	4,953	$94,609
May	2.42	1,989,730	821,970	4,953	$91,528
Jun	2.49	2,106,030	844,490	4,797	$96,877
Jul	2.45	2,034,040	831,540	4,794	$93,566
Aug	2.50	2,102,320	840,200	4,728	$96,707
Sep	2.45	2,060,210	839,310	4,771	$94,770
Oct	2.41	1,983,040	821,180	4,771	$91,220
Nov	2.45	1,964,920	801,040	4,771	$90,386
Dec	2.45	1,988,640	810,940	4,771	$91,477
Avg Total	**2.49**	**24,860,390**	**10,000,000**	**4,847**	**$1,143,578**

Electric rate $0.046/kWh

This approach is better than tracking gross energy consumption, but results in a wide range of values because it only takes into consideration one driver of energy consumption – total production. Most production facilities have other important drivers such as production mix, weather and operational mode, among others. This can impact the usefulness of this information and can negatively impact employee buy-in to supporting energy improvements.

Step 1 – Plan (continued)

Best – Multi-variable regression modeling

Multi-variable regression modeling is often the most accurate and useful method of creating a baseline. This approach uses a mathematical equation, taking into consideration multiple variables including but not limited to product lines, temperature, humidity, days of the week, mode of operation and plant shutdown time.

Example regression model equation

kWh/day = 45,000 + 67*(Cogs) + 74*(Wheels) + (1,500*Cooling Degree Days365) – 26,000*(Weekend)

Once a model is established, it can be used to compare expected daily consumption against actual utility meter readings for each day. Differences between the model and actual energy consumption can be accumulated over time in a useful visual layout called a cumulative sum control chart. The value of this graph represents normalized savings to date and the path of the graph over time can be useful in identifying unexpected energy performance impacts from operation adjustments.

Regression modeling can be done using any number of readily available tools such as Microsoft Excel or open-source statistical software. Unfortunately, effective regression modeling is best done by an experienced and trained statistical modeler. Contact Focus on Energy for assistance in developing a regression model.

Identify opportunities

Best practices are techniques or technologies recognized as being economical and more efficient than common practices. Review best practices in comparison to your equipment and system profiles to identify opportunities for energy efficiency improvements. Focus on Energy can assist you in identifying and prioritizing opportunities for your facility.

Quantify savings and costs of opportunities

Once opportunities are identified, the next step is to estimate the cost savings, including energy, maintenance and installation. Focus on Energy provides technical assistance for quantifying energy savings for projects as needed.

Prioritize projects

This step can be done with your energy team or upper management. Apply criteria such as return on investment, capital cost or ease of installation to help prioritize the projects identified. Select the highest-scoring projects for implementation to achieve your energy-saving goals within time and budget constraints.

Set a goal

Use the prioritized projects to inform a goal. What is achievable this year? The goal doesn't necessarily have to be an amount of saved energy; it could be to maintain current plant performance. Most sources agree intentional plant management can save between 1% – 5% of a plant's annual energy consumption depending on how much a facility has already invested in energy efficiency.

Form an energy team and establish meeting frequency

Effective energy management requires input from many levels of plant operations. The size of an energy team will depend on the magnitude of the annual energy spend. Plants with very large annual energy costs can justify a bigger energy team and more frequent meetings. Smaller plants may only be able to justify assigning the role of energy manager to a single staff person who reports to the general plant management team.

It helps to set a standard agenda to ensure meetings are efficient and effective. Typical energy team meeting agendas have at least two components:

1. Review progress on selected projects and initiatives.
2. Review and discuss performance to date against the baseline.

Step 2 – Do

Regular energy team meetings

The energy team should meet according to the frequency set forth in the planning phase and discuss progress and challenges for the projects identified.

Project management and implementation

Manage each energy project selected for implementation by clearly defining project parameters, assigning responsibilities for project implementation, setting deadlines and undertaking specific tasks needed to implement the project. Progress on projects should be reported during energy team meetings.

Step 3 – Check

Monitoring progress against baseline

At each meeting, the energy team should report on progress against the selected baseline. For a gross energy consumption baseline, how much energy has been consumed to-date and how does it compare to this time last year? For energy-intensity baseline, what was the energy consumed per unit of production last month and how does this compare to the baseline metric? And for regression-based baseline models, over the past month, did the plant consume more energy than the model expected? The team should discuss causes to explain results. Did any implemented projects result in the expected savings?

Figure 1: KPI goal and tracking

This graph depicts KPI tracking of a simple energy intensity KPI

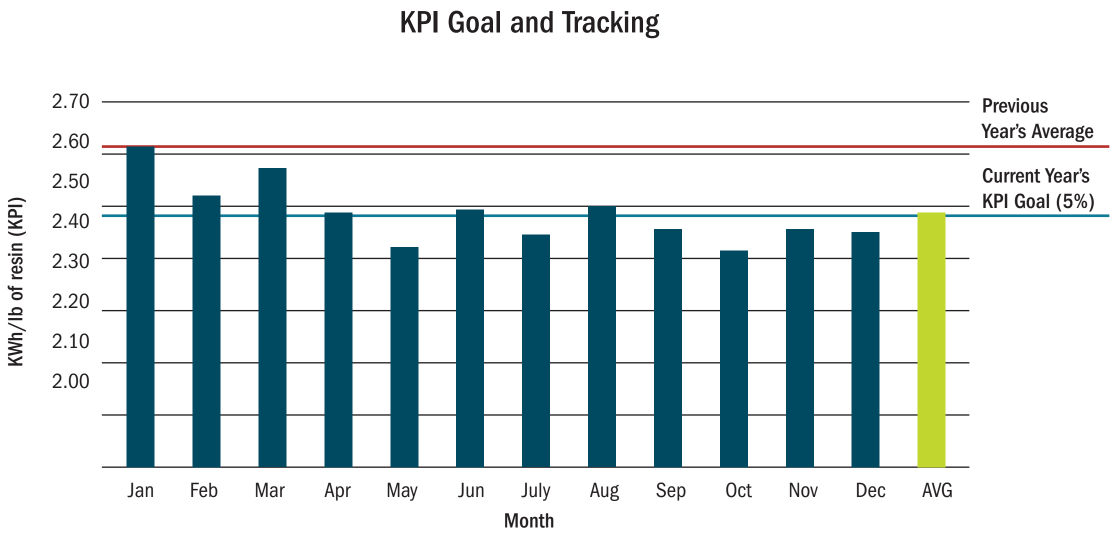
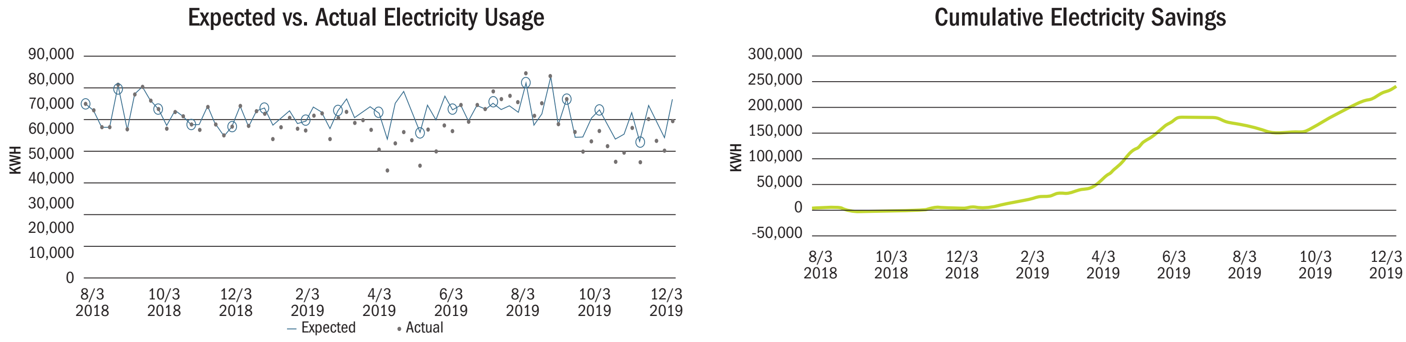


Figure 2: Tracking energy performance

This graph depicts tracking energy performance using a regression model approach.



Reports to management

The energy team should report to upper management at regular intervals. This can include reviewing projects completed, sharing results found using a baseline comparison and discussing progress towards goals.

Step 4 – Act

Acting on results

One of the primary goals of continuous improvement is to constantly adjust tactics and strategies based on actionable data. Each energy team meeting and report to management is an opportunity to recognize a need to act. If the energy performance of the plant is degrading, determine why and what needs to be done. If the expected savings from a project are not being realized, assign a task to find out why. If an established goal is deemed too aggressive, reduce the goal and document lessons learned. Each cycle of continuous improvement will result in lessons learned and can be applied to the planning phase of the next cycle.

Step 5 – Repeat

Repeat the four steps above on a regular basis. Most plants revisit the planning phase at least annually during other regular annual planning cycles.

TECHNICAL BEST PRACTICES

The best practices included in this guidebook relate to process energy use unique to a corn-based ethanol dry mill facility for ethanol production. Additional best practices for common support systems found in most industrial facilities are located in Appendix A.

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PH1 – Combined heat and power

Best practice	Combined heat and power (CHP) systems use steam generation equipment to create electricity to meet plant needs.
Primary area/process	Process steam generation.
Productivity impact	None. Increased operation and management costs associated with the added generators are around $100,000.
Economic benefit	An investment of $3.5 million for a generator, higher pressure boiler with superheater, and additional mechanical work will net a savings of around $650,000 after factoring in reduced electric costs, increased natural gas costs, and added maintenance costs. The estimated payback on the incremental cost for a new installation will likely range from three to five years.
Energy savings	A typical plant will be able to provide 35% to 40% of its electricity by increasing natural gas use by about 10%.
Applications and limitations	The amount of electric power produced increases with boiler pressure. It is suggested to operate a boiler at 650 psig to provide enough pressure for the turbine and still produce 150 psig steam for plant use at the turbine extraction port. CHP operation will not be able to match both thermal and electrical demands of the ethanol plant.
Practical notes	Water consumption may increase due to additional boiler blowdown and makeup. Coordinate with electrical grid operator. Personnel will need to be trained on operation of power generation equipment.
Other benefits	A CHP provides increased plant power reliability by utilizing the grid as backup and storage for electricity. The CHP can be run off boilers powered by any available fuel (fossil or biomass) or the process may be run from gasification of the bran if fractionation is practiced.

PH2 – Combined heat and power with heat recovery steam generator

Best practice	Combined heat and power (CHP) systems utilize a combustion turbine to generate electricity in conjunction with a heat recovery steam generator (HRSG). The HRSG uses waste heat from the turbine to produce some or all the steam required by the plant. “Duct burners” can also be used to provide additional steam output.
Primary area/process	Process steam generation.
Productivity impact	None. There are increased O&M costs associated with the combustion turbine and generator.
Economic benefit	A combustion turbine can be sized to produce all the electricity needed or it can be sized so the HRSG provides some or all the steam needed by the plant. A CHP system sized to produce enough electricity to operate an ethanol plant will produce 20% to 40% of the steam. A system sized to produce all the needed steam would generate three to four times the plant electric requirements. Based on current costs, CHP could reduce annual energy spend by about $2 million.
Energy savings	Results in costs savings but not typically energy savings. Electricity, which is a higher cost source of energy, is created using natural gas, which is a lower cost source of energy.
Applications and limitations	Most useful for processes with significant heat and electric loads. CHP operation will not be able to match both thermal and electrical demands of the ethanol plant.
Practical notes	Coordinate with electrical grid operator. Personnel will need to be trained on operation of power generation equipment.
Other benefits	Provides increased plant power reliability by utilizing the grid as backup and storage for electricity.
Stage of acceptance	CHP processes are common throughout the world and are becoming more common in ethanol plant installations.

PH3 – Optimize heat exchangers

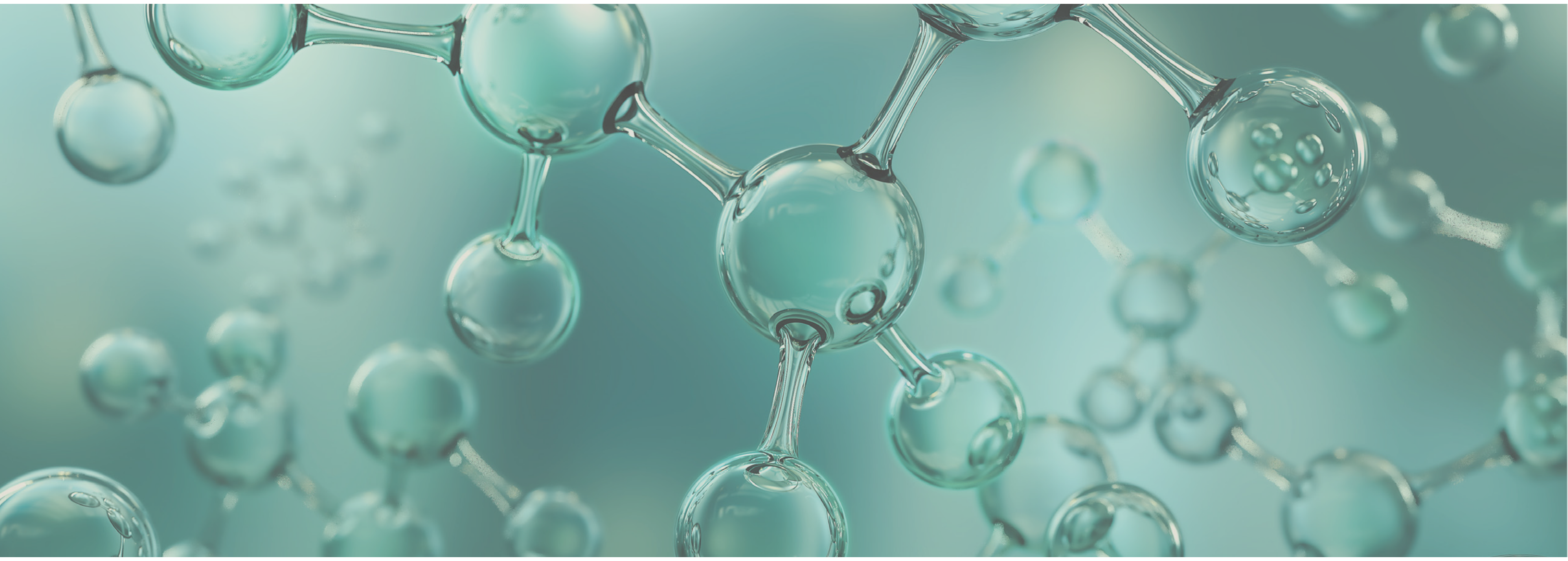
Best practice	Match the heat exchanger size and type to the process application.
Primary area/process	In plants using interchangers. Other exchangers are also possible candidates.
Productivity impact	Can help reduce bottlenecks.
Economic benefit	A 1°F decrease in beer temperature out of the mash/beer exchanger will increase steam cost by about $14,000 for a 50 MGY plant. The cooling tower load decrease is approximately $800 a year per degree cooled in the mash. A management system able to determine the proper cleaning interval can have a payback of less than one year. Additional heat exchangers provide annual savings which can be compared against the cost of the equipment and additional O&M. For example, if a new exchanger decreases mash and increases beer temperature by an additional 50°F, the annual expected energy savings is $73,000.
Energy savings	Regularly cleaning and maintaining the existing heat exchanger will keep it operating as intended, which results in about 43,400 MMBtu per year decrease in boiler demand and 16,000 kWh decrease in cooling tower demand per degree transferred from the mash to the beer.
Applications and limitations	Proper maintenance of heat exchangers is critical to efficient operation. Ensure the process fluids are not corrosive to the heat exchanger materials.
Practical notes	When updating heat exchangers, ensure revising inlet/outlet temperature is not shifting the steam or chilling load from one point to another location in the facility. It is important to optimize the exchangers without causing excessive fouling to decrease cooling and steam loads.
Other benefits	Decreasing the cooling tower load will decrease the water used by approximately 0.40 MGY per mash reduced degree. The increased O&M from additional heat exchangers will be approximately offset by the O&M avoided in the steam or chilled water systems.
Stage of acceptance	Both frame and plate and shell and tube heat exchanger properties and performance are well documented and accepted. However, fluid properties play a significant role in heat exchanger performance, including how often clean in place (CIP) must be applied.

PH4 – Thermal oxidizer heat recovery

Best practice	Recover heat from the thermal oxidizer (TO) or regenerative thermal oxidizer (RTO) exhaust for preheating.
Primary area/process	The exhaust from the TO or RTO is hot and contains a significant amount of water vapor from dryers, making it suitable for recovery with a condensing heat recovery (CHR). The high dew point typical of RTO exhaust allows recovery heat from condensation of water vapor (latent heat) at higher temperatures than is possible with boiler applications.
Productivity impact	None
Economic benefit	Installed cost will range from $1.5 million to $2.5 million for a 50 MGY plant, which includes a runaround loop to circulate the heated fluid. The payback ranges from two to five years depending on the heat sink properties.
Energy savings	When used for beer column feed preheating, utilizing the excess heat can displace approximately 1,000,000 therms of natural gas per year in the boiler if the beer feed can be raised by 300°F. This is partially offset by operation of an additional pumping system loop for exchanger fluid and a fan on the CHR.
Applications and limitations	This measure could be considered a modification of a pollution control system. Check with authorities prior to installation to determine if the air or water permit is affected.
Practical notes	In order to decrease the maintenance on the CHR and improve reliability, it is recommended a runaround loop be used to transfer heat between the CHR and the fluid to be heated. This will incur additional cost (included in estimated cost above) but will improve reliability.
Other benefits	The condensate formed may be suitable for reclamation and reuse in the plant with pre-treatment. Depending on loads, it may be possible to recover additional heat from the same CHR system to preheat dryer inlet air and/or boiler combustion air, with a minimal additional investment.
Stage of acceptance	All equipment is standard.

PH5 – Increase boiler combustion air temperature

Best practice	When possible, draw combustion air from the ceiling to the floor or directly from the ceiling. Use the ambient conditions to remove heat or add heat to process streams without the aid of a chiller or boiler.
Primary area/process	Some facilities have louvers near the floor allowing cool ambient air to be drawn directly into the combustion air fan. Use of deflectors to send the air to the ceiling first will help remove waste heat from the boiler room and increase the combustion air temperature.
Productivity impact	None
Economic benefit	Increasing the combustion air temperature adds energy to the inlet side of the boiler. For a boiler with a steam output of 85,000 pounds per hour (pph), increasing the combustion air temperature by 100F rise on average will save about $11,500 annually.
Energy savings	An increase in ambient temperature from 700F to 800F will reduce the boiler gas consumption 0.2% or 1,900 MMBtu for a 50 MGY plant.
Applications and limitations	Implementation of this improvement does not often require additional capital improvements, but rather changes to operational procedures or minor modifications to wall vents. In some cases, a duct will be necessary to allow the warm combustion air to be efficiently drawn from the ceiling area. The impact of the duct on combustion air fan performance (pressure drop) must be considered in these cases.
Practical notes	None
Other benefits	None
Stage of acceptance	This is a well-established best practice.



PH6 – Eliminate rectifier overhead vapor flow to reflux condenser (Delta T plants only)

Best practice	Make productive use of all rectifier column overhead vapor.
Primary area/process	By design, most of the rectifier column overhead should be condensed in first effect evaporator. In practice, most Delta T plants condense significant amounts of rectifier overhead in the reflux condenser, where heat of vaporization is wasted to the cooling tower. Productive use of rectifier overhead includes increasing syrup solids in forced circulation concentrator, heating beer, evaporator condensate or backset.
Productivity impact	There could be a productivity increase if the process receiving heat is the plant bottleneck.
Economic benefit	Installed cost will range from $0.25 million to $2.5 million for a 50 MGY plant, dependent on where heat is used.
Energy savings	Highly dependent on existing plant heat balance. A plant condensing 50 gpm in reflux condenser will save 77,000 MMBtu annually, or an estimated $307,000, if this heat is put to productive use. Cooling tower energy usage will also be reduced by 305,000 annual kWh.
Applications and limitations	Proper maintenance of heat exchangers is critical to efficient operation. Ensure the process fluids are not corrosive to the heat exchanger materials.
Practical notes	When updating heat exchangers, ensure revising inlet/outlet temperature is not shifting the steam or chilling load from one point to another location in the facility.
Other benefits	The increase O&M from additional heat exchangers will be mostly offset by the O&M avoided in the steam or chilled water systems. Decreasing the cooling tower load will decrease the water used by approximately 7.7 MGY per mash reduced for 50 gpm reduction in overhead condensed in reflux condenser.
Stage of acceptance	All equipment is standard.

SC1 – Raw starch hydrolysis

Best practice	Utilize only enzymes to convert uncooked starch to glucose.
Primary area/process	The alpha-amylase and glucoamylase enzymes for liquefaction and saccharification are developed to work at similar process conditions, therefore eliminating the need to adjust the mash between the two processes.
Productivity impact	There is no direct correlation to ethanol productivity increase, although the process generally increases the quality of the co-product, distiller's grain with solubles (DDGS).
Economic benefit	Eliminates the need for chemicals and energy to alter the temperature, pH, and concentration between the two stages, which is partially offset by the higher enzyme cost. Newer generations of these enzymes can be injected into the piping to the fermentation tanks and have shown an increase in protein in the DDGS co-product. Energy cost savings will be approximately $20,000.
Energy savings	Eliminating the jet cooker will reduce heat loss on the slurry pumping system by 5 psi. Eliminating two plate heat exchangers will eliminate the need for approximately a 60 HP motor and pump. Dependent on pump curves, this will eliminate approximately 300,000 kWh/yr.
Applications and limitations	There are few suppliers of the necessary raw material enzymes necessary.
Practical notes	Utilizing raw starch hydrolysis requires a different management process of the slurry to ensure proper fermentation.
Other benefits	Operations and maintenance costs are reduced by minimizing the number of testing and injection points for chemicals. The removal of the jet cooker eliminates losses in the steam system and decreases the amount of makeup water to the boiler. The water injected at the jet cooker is recovered at the centrifuge, although the loss of condensate will require more frequent boiler blowdown, which increases the water use. A continuous dosing of raw starch hydrolysis enzymes can also include yeast and other nutrients which eliminate slurry holding tanks and yeast propagation tanks, improve mixing, and reduce the potential time for process contamination.
Stage of acceptance	This process is operating in many plants' facilities, but they are under the same management company. No facilities have retrofitted this technology into an existing plant.

F1 – Yeast propagation

Best practice	Utilize the lowest cost means of providing minimum dissolved oxygen content and agitation in yeast propagation tank.
Primary area/process	Evaluate and optimize the yeast propagation air supply delivery to the yeast propagation tanks.
Productivity impact	There is no productivity impact provided current conditions allow the yeast to reach a sufficient level of growth and activity prior to entering the fermentation tanks.
Economic benefit	Compressed air provides four to six times the necessary pressure to provide air to the yeast propagation tanks. Blowers and venturi jets are much more suited to provide air at the right pressure, thereby decreasing the amount of horsepower needed per volume provided. The expected payback is four years dependent upon necessary piping replacement.
Energy savings	The capacity of the yeast slurry to retain the dissolved oxygen in the propagation mix is a function of the amount of air added, bubble size, and consistency of the mix. Thick propagation slurries (80:20 mash-to-water ratio and higher) often require the addition of compressed air to make up for the lowered capacity for retaining dissolved oxygen. Slurry mixes can be reduced to equal parts mash and water. For 3,200 cubic feet of 80:20 yeast slurry aerated at 1 cfm/cf for 1,328 hours a year through air compression, the effective usage in the air compressor utility is 900,000 kWh ($54,000). Diluting the slurry mix with 20% more water, a comparative blower system can be installed for approximately $100,000 and use 450,000 kWh ($27,000). A venturi jet induction system with oxygen monitoring has the opportunity to reduce the electricity cost up to 40% more due to increased oxygen transfer ($16,000), although the tank will have to be re-piped.
Applications and limitations	The cost of installation will vary depending on the existing set-up of the aeration system and potential reuse of the existing piping.
Practical notes	Yeast propagation is designed to rehydrate, condition and increase yeast populations using their natural reproduction capabilities as living organisms. Aeration is required to increase the dissolved oxygen levels to a point where exponential growth of yeast cells occurs. One sign of inadequate aeration is increased ethanol production in the propagation tank. Limiting the amount of ethanol produced in propagation is a good sign the yeast is respiring aerobically.
Other benefits	The venturi injection system is relatively maintenance free because it has large nozzles. A coarse air bubbler diffuser tends to become clogged, which increases the load on the blower and oxygen flow through the piping. By increasing the water proportion of the yeast slurry mix, 0.5 MGY of additional water is added to the yeast propagation tank. This water should be offset by an equal reduction in the corn slurry entering the fermentation tanks to keep the optimum fermentation slurry consistency.
Stage of acceptance	Adequate aeration is commonly achieved by air inductors installed on the piping going into the propagation tank, pulling air into the propagation mix as the tank fills and during recirculation.

F2 – Direct yeast injection

<table>
<tr><td>Best practice</td><td>Direct injection of cream or liquid yeast into fermentation tanks from a sterile environment replaces the yeast propagation or dry yeast hydration.</td></tr>
<tr><td>Primary area/process</td><td>By direct yeast injection, the plant can inject the exact yeast strain for maximized alcohol production into the fermentation tank.</td></tr>
<tr><td>Productivity impact</td><td>Limited studies have shown a 3% to 5% increase in plant throughput. There is also a slight increase (<0.5%) in ethanol yield per bushel through better optimization of fermentation, improved flexibility in handling and dosing, and eliminating the need for feedstock to propagate yeast.</td></tr>
<tr><td>Economic benefit</td><td>Assume your dry yeast costs $X and the operating costs for propagation and chemical additions is $1.5X. Cream yeast is approximately $4.5X with minimal operations and maintenance costs. This cost is offset by an increase in yield. Capital costs for a cream yeast system varies based on operations and system design. Basic assumptions about the system should include a dosing system and temporary storage tanks.
<table>
<tr><th colspan="4">APPROXIMATE COSTS ($)</th></tr>
<tr><th>PLANT SIZE (MGY)</th><th>DRY YEAST MATERIAL+</th><th>CREAM YEAST SYSTEM ADD. COST+</th><th>YIELD INCREASE OF 0.1%</th></tr>
<tr><td>50</td><td>($150,000)</td><td>($300,000)</td><td>$645,000*</td></tr>
<tr><td>100</td><td>($300,000)</td><td>($600,000)</td><td>$1,290,000*</td></tr>
</table>
+ Does not include operations or infrastructure costs
* Lalleland Ethanol Technology based on $2 per gallon ethanol</td></tr>
<tr><td>Energy savings</td><td>The propagation tank(s) are replaced by a dosing system, eliminating the 250,000 to 900,000 kWh/year of the aeration system and 60 MMBtu/year heat loss from an insulated propagation tank. Some cream yeasts may require cooling on hot days, approximate at 15,000 kWh/year from the existing chiller.</td></tr>
<tr><td>Applications and limitations</td><td>Cream or liquid yeast can only be stored a short time (two to four weeks) under standard conditions. It can be stored up to three months when refrigerated. Dry yeast can be stored up to 24 months.</td></tr>
<tr><td>Practical notes</td><td>A 50 MGY plant will require one tanker truckload every 10 to 14 days. Productivity increases are not guaranteed. It is recommended plants run trials of cream yeast prior to investment.</td></tr>
<tr><td>Other benefits</td><td>O&M costs are reduced by eliminating the yeast propagation tanks and the associated cleaning and anti-microbial growth regimens. Furthermore, the lag phase associated with dry yeast is eliminated thereby decreasing the time when microbial growth can occur.</td></tr>
<tr><td>Stage of acceptance</td><td>Cream or liquid yeast is used for approximately 85% of the yeast in the U.S. baking industry.</td></tr>
</table>

F3 – Improve yeast performance

Best practice	Use yeast with high thermal, alcohol, and osmotic tolerance to decrease fermentation time, increase feed concentration, and increase alcohol concentration.
Primary area/process	Purchase yeast with the highest thermal and alcohol tolerance and operate the fermentation near to the maximum tolerated levels.
Productivity impact	Allow operators to decrease fermentation times and increase ethanol yield per bushel.
Economic benefit	According to kinetics theory, additional heat will reduce fermentation time by approximately 25% when the temperature is raised from 95°F to 140°F. Increasing alcohol tolerance in yeast means it is less likely to pass sugars through the fermentation basin without converting them to alcohol.
Energy savings	Increasing fermentation temperature will reduce the need to cool the mash and heat the beer. A slight amount of additional heat loss through the fermentation tank walls will increase heating load by 1.25 therms per fermentation batch but will produce more alcohol per batch.
Applications and limitations	Monitoring the propagation and fermentation tanks is necessary to operate near the yeast limits and determine if yeast is not performing to expected results. Contact yeast supplier or fermentation specialist if yeast is not performing to specifications.
Other benefits	Increased limits on alcohol concentration mean less water is needed to dilute the mash and beer, reducing water volume to be added to the slurry.
Stage of acceptance	Yeast strains are improving continually and newer versions are brought into the marketplace relatively easily.

CP1 – Pre-process fractionation

Best practice	Pre-process fractionation breaks the corn kernel into germ, pericarp, and endosperm prior to processing.
Primary area/process	The pre-processing replaces the hammer mill at the front end of the ethanol process with a dry fractionation grinder, separation equipment, and two additional silos.
Productivity impact	The process is not 100% efficient at separating the starch from the germ and bran (unfermentable material). When the unfermentable material is removed from the ethanol production process, less starch per bushel is available for fermentation. This results in a reduction of ethanol produced per bushel of approximately 5%. Including this reduction, the capacity of the existing ethanol production process is increased by 10% to 15% because of the increased starch content of the slurry, processing more bushels of corn, and removing unfermentable materials. The whole stillage volume is decreased by 40% to 50% and both bran and germ are produced separately.
Economic benefit	The potential payback ranges from one to 10 years based upon assumptions of average prices for ethanol and four additional co-products (see Appendix X for pricing assumptions). The capital costs of retrofitting may cost as much as the plant construction but are typically between $25 and $30 million.
Energy savings	Energy is saved throughout the ethanol production process by eliminating the heating, cooling, drying, and pumping of unfermentable material at a rate equal to the percentage increase in ethanol, represented by an increase in the bushels processed by a similar amount of energy consumed. This does not include any energy process loads for co-products from the fractionation. The thermal load is decreased 2,775 Btu/gallon and the electrical load is decreased by 0.07 kWh/gallon, which equates to an approximate reduction of 420 kW demand for a 50 MGY plant.
Applications and limitations	The de-braned/de-germed distillers grain has a different physical and chemical makeup than standard distillers grains.
Practical notes	There is a steep learning curve when changing to fermenting with fractionated material; it is different than fermenting whole corn.
Other benefits	The fractionated material not passed through the ethanol processing plant is dry and stable, as opposed to being part of the distillers grain. The reduction in pass-through material will reduce the water usage per gallon of ethanol by a similar percentage as the energy per unit: approximately 0.3 gallons water/gallon ethanol or 15 MGY water for a 50 MGY plant.
Stage of acceptance	Fractionation is a common procedure in many other grain processing facilities but is generally a wet process. Newly constructed ethanol plants are including dry fractionation and several retrofits are underway.

CP2 – Wet distillers grain co-product

Best practice

Selling the wet distillers grain (WDG or WDGS) to local customers eliminates the need to dry the material.

Primary area/process

Wet distillers grain is produced from decanting of whole stillage to approximately 30% to 40% solids. This product has a shelf life varying from three days to 14 days dependent on weather. Facilities can develop relationships with local agricultural producers as an outlet to sell their WDG. Several studies have looked at the potential for land spreading, although this has not been approved by environmental agencies.

Productivity impact

The production of ethanol and WDG is not affected by this operation, but there is a need to handle the delivery to customers on a nearly just-in- time basis. Without an efficient distribution system, the cost of this operation will increase because of the necessary storage and handling.

Economic benefit

Distributing WDGS eliminates the need to dry the co-product beyond the decanter and thin stillage evaporator to provide a saleable product. This is offset by the increased amount of material transported to the customer. The transportation costs are based upon a 200-mile average delivery for DDGS and 80-mile average delivery for WDGS.

	DDGS	WDGS
Material weight (tons)	157,600	405,000
(FOB plant) material sale price ($/ton)	$135.00	$47.00*
Sale revenues	**$21,276,000**	**$19,350,000**

Thermal drying energy (1,300 btu/lb. water)	$2,562,560	$0
Electric dryer energy	$150,000	$0
Evaporator steam load	$70,000	$70,000
Load out material handling	$400,000	$800,000
Quality assurance (1 test per batch)	$700,000	$700,000
Transaction costs ($5/load)	$40,000	$100,000
Total costs	**$3,922,560**	**$1,670,000**

Est. gross income	**$17,353,440**	**$17,680,000**

*(7/5/19)

Note: A sensitivity analysis on the input energy prices shows a 5% increase in energy prices correlates to a 25% reduction of DDGS gross income compared to 1% reduction for WDGS.

Energy savings

Approximately 650,000 MMBtu of natural gas consumption per year is eliminated at a 50 MGY plant with a drum dryer switching from DDGS to 100% WDGS. This does not include heat recapture on the dryer, oxidizer or material cooling. The electric energy reduction is primarily associated with the dryer and exhaust system which is turned off when WDGS is produced, estimated at 1.8 million kWh per year.

Applications and limitations	Spoilage is a major concern for WDG and WDGS. Several options exist to increase the shelf life of the material, although none have been universally recognized as the optimal solution. The most cost-effective option is an effective just-in-time delivery system with the option to include other methods. Other methods include vacuum preservation, preservative addition, ensilage with crop residue, and land spreading. Steps should be taken to prevent freezing.
Practical notes	The market for distillers wet grain is local and limited, so prices can be volatile. Many markets are already saturated. By contrast, there is a global market for distillers dry grain. If heat recovery is used to recover heat from a dryer or regenerative thermal oxidizer (RTO), any offset of energy recovered will need consideration as this may reduce cost savings due to reduction in exhaust water vapor. This can affect condensing and non-condensing heat recovery systems.
Other benefits	Distillers grain dryers are generally responsible for 60% of the air emissions at a typical ethanol plant. Reducing the amount of material dried will drastically reduce overall air emissions. There are no water savings for the ethanol plant, although the water contained within the wet distillers grain is conserved as a liquid. Additional mechanical drying will increase solids and theoretically increase shelf life with minimal additional energy consumption.
Stage of acceptance	A 2007 analysis by the Renewable Fuels Association determined 37% of distillers grain with solubles was sold as wet feed. Approximately 35% of dairy producers in Wisconsin are utilizing distillers grains (DG).
Resources	University of Nebraska Extension, South Dakota State University Cooperative Extension Service, Purdue University Cooperative Extension Service.

CP3 – Increase syrup solids content

Best practice	Increase syrup solids content to reduce natural gas usage in DDGS dryer, using high solids evaporator.
Primary area/process	Syrup is created by evaporating water from thin stillage in multiple effect, falling film evaporators. Solids content of syrup is limited by its fouling tendencies and high viscosity. Syrup can be further concentrated in a forced circulation evaporator, where boiling occurs in a flash tank rather than on heat transfer surface.
Productivity impact	The production of ethanol is not affected by this operation unless the plant bottleneck is the DDGS dryer. If the dryer is a bottleneck, production could be increased.
Energy savings	Removing 20 gpm from dryer would save about 120,000 MMBtu annually (assuming high solids evaporator is driven with waste heat). A multiple effect high solids evaporator can still save significant amount of energy even if driven with steam.
Applications and limitations	In order to save energy, high solids evaporator either must be driven with waste heat or be multiple effect. A multiple effect evaporator takes advantage of steam economy. Maximum achievable solids are dependent on viscosity and scaling tendencies of syrup.
Other benefits	Distillers grain dryers are generally responsible for 60% of the air emissions at a typical ethanol plant. Reducing the amount of material dried will drastically reduce overall air emissions. Any water removed from syrup is available for re-use in making ethanol, therefore reducing the need for well water.
Stage of acceptance	There are several ethanol facilities in Wisconsin who have implemented projects to increase syrup solids.

CP4 – Indirect dryer

Best practice	An indirect steam tube dryer eliminates combustibles from the dryer exhaust, allowing removal of the thermal oxidizer.
Primary area/process	A closed pressurized steam loop created by the evaporated water vapor is circulated with heat input through an air to air heat exchanger. A side stream of steam is removed from the drum which is condensable to recover the additional heat for preheating.
Productivity impact	None
Economic benefit	The capital cost of an indirect dryer is approximately the same as a direct fired dryer and regenerative thermal oxidizer (RTO) unit for a 50 MGY plant. Adding a heat recovery system to an indirect dryer for pre-drying WDG has a payback of two years for a 50 MGY plant. Considering the full cost of a retrofit with additional heat recovery on an operational direct fired system, the payback would be approximately five years.
Energy savings	Thermal energy consumption to evaporate water is approximately equal to standard dryers, but the exhaust heat is more accessible because it does not include combustibles. When used for preheating the wet distillers grain it can reduce the overall heating load, after startup, by approximately 40% of a conventional direct fired drum dryer. Once started and warmed up, the recaptured heat will reduce the overall heat required to be supplied by the boiler. The fans and pumps associated with an indirect dryer use a significant amount of energy, so it is important to evaluate the electrical usage of any indirect dryer system prior to purchasing. There can be as much as a 30% difference in energy usage between systems, or approximately $150,000. This is normally offset by removal of the thermal oxidizer fan.
Applications and limitations	An indirect dryer cannot be retrofitted within the existing dryer.
Practical notes	The non-contact system eliminates combustible material and oxygen within the dryer, greatly reducing the risk for fire or explosion.
Other benefits	The protein within the DDGS is not denatured during the indirect heating process and the potential for burning the material is reduced; however, the temperature is high enough to deactivate bacteria. These items increase the value of DDGS as a livestock feed (this value is not included in the Economic benefit calculation). The Economic benefit is decreased when increasing portions of the co-product are sold as wet distiller's grain.
Stage of acceptance	Indirect dryers have been installed in several plants designed in 2007. Indirect steam dryers have been in operation in grain drying, baking, and industrial other drying industries for decades.

CA1 – Heat of compression compressed air dryer

Best practice	Utilize a heat of compression (HOC) air dryer if -40°F dew point compressed air is needed or if air is supplied by oil-free air compressor.
Primary area/process	As air is compressed, it is heated. HOC dryers use this heat to regenerate the dryer desiccant. Because of this, HOC dryers have the lowest energy usage of any compressed air dryer. A drum unit has a small motor to turn the drum, some require a small amount of purge air, and others may not use any energy.
Productivity impact	HOC dryer does not affect plant productivity. It may negate the need for a larger air compressor if existing is slightly short on capacity.
Economic benefit	Cost for 1,000 CFM unit (typical for ethanol plant) should be between $35,000 and $50,000.
Energy savings	HOC dryer for 1,000 CFM compressor would save at least $12,000 annually vs. heatless purge, desiccant dryer.
Applications and limitations	HOC dryers cannot be used with oil injected air compressors.
Practical notes	In plants where only +40°F dewpoint air is required (no compressed air outdoors or in unheated buildings), a cycling refrigerated air dryer is likely more cost effective.
Other benefits	None
Stage of acceptance	HOC dryers are produced by several manufacturers.

CA2 – Vacuum purge, desiccant compressed air dryer

Best practice	Utilize vacuum purge, desiccant air dryer if -40°F dewpoint compressed air is needed and heat of compression dryer is not applicable.
Primary area/process	Most desiccant air dryers use compressed air and/or electrically generated heat for regeneration of desiccant. Vacuum purge dryer only requires a small vacuum blower to draw moisture from desiccant.
Productivity impact	Does not affect plant productivity. It may negate the need for a larger air compressor if existing is slightly short on capacity.
Economic benefit	Cost for 1,000 CFM unit (typical for ethanol plant) should be between $30,000 and $40,000.
Energy savings	Vacuum purge, desiccant dryer for 1,000 CFM compressor would save about $11,000 annually vs. heatless purge, desiccant dryer.
Applications and limitations	Vacuum purge, desiccant dryers can be used with any air compressor.
Practical notes	In plants where only +40°F dewpoint air is required, a cycling refrigerated air dryer is likely more cost-effective.
Other benefits	None
Stage of acceptance	Vacuum purge, desiccant dryers are manufactured by at least two companies.

PC1 – Predictive modeling control

<table>
<tr><td>Best practice</td><td>Utilize a modeling program for plant operator decisions to optimize the entire ethanol production process based upon multiple processes.</td></tr>
<tr><td>Primary area/process</td><td>The software controls all the processes in the plant and has directions to optimize efficiency of the plant through automatic adjustments based upon current operating conditions.</td></tr>
<tr><td>Productivity impact</td><td>Each process will be managed based upon optimizing the plant productivity while reducing energy costs.</td></tr>
<tr><td>Economic benefit</td><td>The predictive modeling is generally sold in modules addressing a certain portion of the process. The system will keep processes coordinated, thereby reducing the operating costs associated with those processes. Generally, the software designers will look for the opportunities where the payback is less than one year based upon an estimated cost of $250,000 per module.</td></tr>
<tr><td>Energy savings</td><td>The software reduces the cost of energy used per gallon of ethanol based upon operating processes and the cost of energy. These savings vary depending on operating conditions, but typical savings can be measured in yield improvements.
<table>
<tr><th colspan="4">VALUE OF ANNUAL YIELD IMPROVEMENT</th></tr>
<tr><th>PLANT SIZE (MGY)</th><th>0.01 GAL./BU.</th><th>0.05 GAL./BU.</th><th>0.10 GAL./BU.</th></tr>
<tr><td>50</td><td>$377,000</td><td>$1,890,000</td><td>$3,780,000</td></tr>
<tr><td>100</td><td>$754,000</td><td>$3,780,000</td><td>$7,560,000</td></tr>
</table>
Source: Lalleland Ethanol Technology, based on $2/gal ethanol.</td></tr>
<tr><td>Applications and limitations</td><td>The modeling software controls and automated reactions are only as strong as the original program, so ensure the designer is familiar with ethanol production process.</td></tr>
<tr><td>Practical notes</td><td>All plants are unique and generally cannot find an off-the- shelf software program. This makes the purchase and installation of the control software more expensive than standard operating software. The greatest energy savings will come from a full predictive control with multi-variable input that is optimized for an individual plant.</td></tr>
<tr><td>Other benefits</td><td>An increase in alcohol yield per bushel will increase saleable ethanol with a minor increase in other production costs. The software can utilize the cost of water as a variable in the calculations and reduce use when economically feasible.</td></tr>
<tr><td>Stage of acceptance</td><td>All plants have some version of software controls for operation and most have some level of predictive control. The paper industry has customized and utilized this type of programming for many years.</td></tr>
</table>

PC2 – Temperature gauge calibration

Best practice	Regularly maintain and recalibrate temperature gauges.
Primary area/process	Maintain temperature gauges to ensure correct measurements for control system.
Productivity impact	None
Economic benefit	A temperature measurement in the liquefaction tank 10°F lower than actual temperature requires $23,000 of thermal energy per year to maintain the additional temperature in the slurry flow. The beer exiting the fermentation tank will require an additional amount of thermal energy per year if the measurement is one degree higher than the actual temperature in the fermenter. The overall annual Economic benefit will vary dependent on condition of the gauges.
Energy savings	The thermal energy necessary per degree additional thermal energy needed because of an inexact temperature reading is approximately 4,000 MMBtu/year. If additional cooling is necessary, the cooling tower will require an additional 16,000 kWh/year.
Applications and limitations	Proper maintenance of instrumentation is necessary for efficient operation.
Practical notes	ASTM International provides several laboratory procedures for calibrating different thermometers. In most instances, a handheld calibrator or multiple thermometer readings can identify an incorrect measurement.
Other benefits	More accurate temperature readings will help operators maintain optimum temperature for biological processes. There is minimal water savings associated with minimizing use of the cooling tower.
Stage of acceptance	Maintenance of temperature sensors is standard practice, although the task is many times overlooked by operators.

PC3 – Automatic control of reflux rate

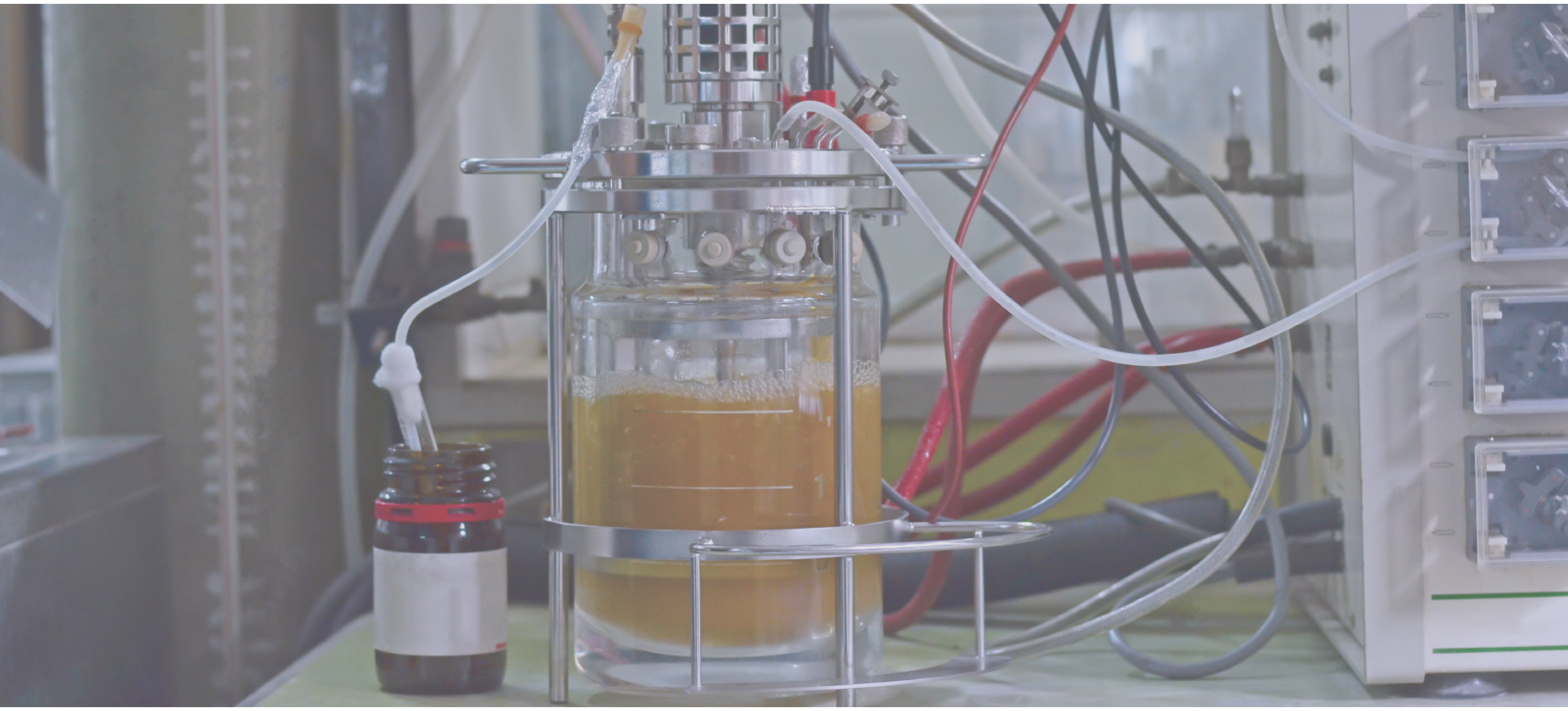
Best practice	Reflux rate is varied to achieve the desired ethanol content "proof" in rectifier column. Proof can be more precisely controlled by automated systems, but in many plants this important process parameter is controlled manually by operators. Excessive reflux does not increase proof but can result in higher steam usage inside stripper.
Primary area/process	Most plant designs include automatic systems, which utilize a temperature/pressure curve to control proof. Many systems are taken out of service because of inaccurate sensors or poor control tuning. Periodic sensor calibration, along with control loop tuning, should allow consistent automatic operation. Another option is to use a Coriolis type mass flowmeter instead of temperature/pressure relationship to control proof.
Productivity impact	A productivity increase is possible if plant bottleneck is in this portion of the process.
Economic benefit	If better control results in average reflux rate being decreased by 10 gpm, boiler gas demand will be reduced by about 15,400 MMBtu annually. This amount of natural gas is worth $62,000 at $4/MMBtu.
Energy savings	A preventive maintenance (PM) program needs to be established for these sensors to ensure reliability and repeatability.
Applications and limitations	Periodic lab tests should be conducted to confirm accuracy.
Practical notes	None
Stage of acceptance	Some plants may already be effectively controlling reflux rate with automatic systems.

E1 – Membrane separation of ethanol and water

Best practice	Membranes have been developed to draw water through the material and not allow ethanol to pass, creating 200-proof ethanol.
Primary area/process	Due to the high cost of membranes, their use has usually been limited to processing the molecular sieve regeneration stream. Normally, this stream goes back to the rectifier column, where its presence requires increased reflux flow.
Productivity impact	There could be productivity increase if current plant bottleneck were in the rectifier/side stripper systems.
Economic benefit	None
Energy savings	Typical energy savings for a system treating molecular sieve regeneration stream is 1,000 to 2,000 Btu per gallon on ethanol produced.
Applications and limitations	Membrane separation can increase capacity, but only if distillation is the plant bottleneck. Plant heat balance needs to be thoroughly understood to ensure a productive use for waste heat from membrane separation system.
Practical notes	Installed cost can be $2 million dollars or more.
Other benefits	None
Stage of acceptance	Multiple installations in Wisconsin.
Resources	Whitefox Technologies, Mitsubishi Chemical.

E2 – Ethanol fermenter cooling loop control system

Best practice	Fermentation pumped through heat exchangers with minimal control.
Primary area/process	The commercial production of fuel ethanol requires a fermentation step where yeast consumes sugar and excretes alcohol and carbon dioxide. The fermentate pumps are typically sized and operated for the worst-case condition, resulting in them circulating at a much higher rate than needed and wasting energy. Addition of VFDs on the fermentate pumps and control logic can minimize the pumping energy needed while keeping temperatures within the optimum range.
Productivity impact	None
Economic benefit	As much as $200,000 depending upon VFD needs. Payback in one to two years.
Energy savings	Energy savings of 35% to 40% are typical. Electric savings commonly range from 300KW to 600KW and 2,500,000 to 5,000,000 annual kWh.
Applications and limitations	Project ROIs will depend on the size of the pump motors, VFD costs, and hours/volume of the operation.
Practical notes	None
Other benefits	None
Stage of acceptance	Four ethanol plants in Wisconsin have adopted the technology.



E3 – Thin stillage solids separation

Best practice	Remove suspended solids from thin stillage. Thin stillage solids separation can be accomplished with a dissolved air floatation clarifier (DAF) or dedicated centrifuge system.
Primary area/process	Whole stillage from the beer column is typically separated into wet cake and thin stillage using a centrifuge (decanter). The centrifuges can be adjusted to provide greater solids content of wet cake (less moisture) at the expense of increased levels of suspended solids in thin stillage.
Productivity impact	Reducing suspended solids of backset allows the addition of slightly more fermentable material per batch.
Economic benefit	Slightly more ethanol product and reduced DDGS dryer gas usage.
Energy savings	Dryer gas savings is dependent on wet cake solids increase.
Applications and limitations	Wet cake solids increase may be limited by centrifuge design
Practical notes	Removing suspended solids from thin stillage retains the benefits of higher wet cake solids, but without the determents of high solids content in thin stillage.
Other benefits	Benefits of thin stillage solids separation include ability to increase wet cake solids (reduced dryer energy), increased production (room for more fermentable material due to lower solids content in backset), reduced evaporator fouling, reduced plant water consumption (less water loss out of dryer stack), and reduced RTO gas consumption.

E4 – Replace vacuum eductor with liquid ring vacuum pump

Best practice	Use a liquid ring vacuum pump (LRVP) in place of liquid eductors in the vacuum system to create the vacuum necessary for the thin stillage evaporators or molecular sieve regeneration.
Primary area/process	The evaporator normally requires a vacuum pressure more efficiently provided by a LRVP. The vacuum system must be redesigned to ensure the vapor condenser matches the revised LRVP. Before deciding to replace pumps, the plant operator should compare system curves for specific plant characteristics.
Productivity impact	None
Economic benefit	Payback of two years or less.
Energy savings	The pump motor power necessary can be reduced by as much as a factor of four. Both the LRVP and eductor pump can operate on a variable frequency drive although control must be carefully considered to avoid erratic evaporator operation.
Applications and limitations	The LRVP must be properly matched to the condenser. Sizing is more involved than simply changing a pump. When installing a LRVP, the liquid transfer function normally accomplished by the eductor pump needs to be provided for.
Practical notes	A properly operating vacuum system will dictate evaporator performance.
Other benefits	None
Stage of acceptance	LRVP are common for processes requiring medium vacuum pressure and are often used on evaporators in other industries.

E5 – Organic Rankine cycle electricity generation

Best practice	Recover low-grade waste heat or utilize a pressure drop to produce electricity using an organic Rankine cycle (ORC) generator.
Primary area/process	An ORC generator can capture and utilize energy normally dissipated by a pressure differential or low-grade outlet. These units are generally small and are sized based upon the existing operating conditions. In most applications, they are not efficient enough to operate as a main power-generating facility, but rather as a waste-energy recovery unit.
Productivity impact	None
Economic benefit	Two to four-year payback with an estimated cost of $200,000 to $400,000.
Energy savings	Low-grade waste heat (250°F) recovered can be utilized to produce electricity at about 10% efficiency. Based upon this efficiency, this emerging best practice should only be installed on waste heat streams not recoverable for thermal energy.
Applications and limitations	This system relies on waste heat of approximately 250°F. Many plants will have more productive uses for waste heat.
Practical notes	The system can also operate solely on a pressure drop of at least 15 psi in a plant. Large natural gas line pressures for ethanol plants are as high as 650 psig and have plant fuel use around 250,000 MM cubic feet per month. The turbo expander can provide the regulated pressure reduction and generate 500 kW and about 140 tons of cooling via the Joule-Thompson cooling effect.
Other benefits	None
Stage of acceptance	To date, very few units have been installed in the United States.

E6 – Reconfigure evaporator and beer heating system (Delta T plants only)

Best practice	Reconfigure evaporator to eliminate whole stillage pre-evaporation.
Primary area/process	Original plant heat balance design is based on most of the rectifier overhead being condensed in the evaporator. In practice, this is normally not the case with large quantities of rectifier overhead being condensed in the reflux condenser. Converting evaporators to thin stillage operation and flash cooling whole stillage to heat beer will put a higher percentage of rectifier overhead to productive use, while reducing plant steam usage by 5% to 10%.
Productivity impact	Productivity could increase if evaporators are limiting factor to production.
Economic benefit	Two to four-year payback with an estimated cost of $1 to $2 million.
Energy savings	Reduced steam usage at beer preheater due to increased beer temperature.
Applications and limitations	Only applicable to Delta T designed plants.
Practical notes	Provisions to clean beer side of flash heat exchangers on the run should be included in design.
Other benefits	Reduces steam usage at beer preheater, eliminates whole stillage pre-evaporation, improves centrifuge operation, reduces evaporator fouling, and results in higher syrup concentration.
Stage of acceptance	Multiple plants in Wisconsin have implemented this design.

APPENDICES

Appendices

Appendix A

Appendix B

Appendix C

Appendix D

Appendix A

Industrial support system best practices

The following are key energy best practices for common supporting systems in industrial facilities. Contact Focus on Energy for more information on these best practices, free technical support to estimate the best practice energy savings for your systems and possible financial incentives.

Compressed air	• Reduce system pressure • Repair leaks • SS vs. TS	• Variable inlet volume • Variable speed control • Energy-efficient motor
Lighting	• Light meter used to verify levels • LED lighting • Occupancy sensors • Lights off during process shutdown	• Task lighting is maximized • Night lighting is turned off • LED exit signs
Motors	• Premium efficiency motor vs. repair • Cogged belts vs. V-belts	• Premium efficiency motors specified on new equipment
Pumps	• Trim impeller to meet maximum load • Use variable speed drive (VSD) instead of throttled control • Use VSD instead of bypass control	
Area comfort heating	• Reduce waste heat • De-stratify heated air in plant • Control heating to desired temperature • Use infrared heating	• Optimize cubic feet per minute air exhausted • Automatic temperature control • Minimize heat to storage areas
Comfort cooling	• Install removable insulation • Minimize unnecessary ventilation • Minimize moisture released	• Higher efficiency air conditioning • Optimize room air temperature
Dehumidification	• Reduce humidity load • Accurately controlling humidity • Optimize ventilation	• Desiccant dehumidification • Minimize reheat energy
Refrigeration	• Thermosiphon • Evaporator fan control • Floating head pressure • Scheduled maintenance – Clean filters – Low refrigerant charge	• Automatic air purge • Recover flash steam

Steam systems	• Reduce steam pressure • Steam trap maintenance • Minimize blowdown • Insulate pipes	• Improve boiler efficiency • Heat recovery for boiler blowdown • Increase condensate return • Stack economizer
Ventilation	• Direct fired make-up units • Better ventilation management	• De-stratified air
Wastewater	• Fine-bubble diffusers • Automatic controlled DO sensors/VSDs	• Heat recovery on anaerobic digester • Unneeded aeration basins are shut off
Fan systems	• Reduce excess flow • Eliminate flow restrictions • Correct poor system effects	• Optimize efficiency of components • Correct leaks in system • Optimize fan output control
Process cooling	• Use VFDs • Float head pressure • Use of free cooling (fluid cooler) • Use of free cooling (cooling tower)	• Match chilled water pumps • Insulate pipes and vessels • Process to process heat recovery
Process heating	• Optimize combustion air fuel ratios • Preheat combustion air • Insulate pipes and vessels • Schedule cleaning of heat exchangers	• Condensing heat recovery • Process to process heat recovery • Ultra-filtration for condensation
Vacuum	• Optimize total cost for conveying • Choose appropriate vacuum pump	• Optimize vacuum pressure • Eliminate vacuum leaks

Appendix B

Benchmarking your ethanol plant

Plant benchmarking

Benchmarking will allow previously constructed plants to compare their energy use to those recently constructed and serves as an energy Key Performance Indicator (KPI) goal. The opportunity for improvement through adoption of the best management practices can bring older plants energy use in line with newer designs. The most advanced best practices may also provide the opportunity for older plants to outperform the recently designed plants and for new plants to improve their performance.

The following benchmark information was synthesized from a variety of sources, including actual plant energy-use data, Ethanol Benchmarking and Best Practice (MnTAP 2008), U.S. Ethanol Industry Efficiency Improvements 2004 to 2007 (Christianson & Assoc. 2008), SEC filing information, and performance guarantees from design firms. It was confirmed by comparison to various modeling programs and standard assumptions made by industry professionals.

The benchmarking of ethanol plants is based on a plant producing ethanol and dried distillers grains with solubles (DDGS), and venting CO_2 to the atmosphere. Table 1 below shows benchmark energy and water use for the standard new 50 MGY plant. As the plants increase in size, efficiencies of scale often show that these benchmark estimates will decrease with similar designs, indicating greater efficiency.

Table 1: Benchmark plant energy use

	STANDARD ENERGY USE PER GALLON*	50 MGY PLANT
Electricity	0.57 kWh/gal.	28,500,000 kWh/yr.
Thermal	0.28 therm/gal.	1,400,000 MMBtu/yr.
Total energy (elec. & thermal)	30,000 Btu/gal.	1,500,000 MMBtu/yr.
Make-up water	3.00 gallons/gal.	150,000,000 gal./yr.

*Based on 200-proof ethanol

Process benchmarking

Benchmarking information is used to establish best practices based upon the energy used in the total plant. Using existing modeling and theoretical calculations, the following table is provided to estimate the energy usage of different standard processes within a plant.

Table 2: Typical energy consumption per process[1]

PROCESS	MAJOR EQUIPMENT	ELEC. KW	NAT. GAS THERMS	ELEC. BTU/GAL[2]	THERMAL BTU/GAL[2]	TOTAL ENERGY PERCENT	TOTAL COST PERCENT
Grain handling	Hammermills, conveyors, dust collectors fans	443	0	251	0	1%	2%
Starch conversion	Pumps, jet cooker, agitators	167	3,180,622	95	6,361	21%	19%
Fermentation	Agitators, pumps	292	0	165	0	1%	1%
Distillation	Reboilers, columns	25	3,395,074	14	6,790	23%	20%
Dehydration	Mole sieve, pumps	16	107,900	9	216	1%	1%
Separation[3]	Centrifuge, evaporators	1,168	320,949	662	642	4%	8%
Drying	Rotary drum dryers (1400Btu/lb)	1,176	6,950,000	666	13,900	48%	46%
Utilities[4]	Thermal oxidizer, cooling tower, air compressor, boiler	570	0	323	0	1%	3%
Totals		**3,857**	**13,954,544**	**2,186**	**27,909**		

Assumed plant production is 50 MGY. Assumed annual run time is 8,300 hours.

This is a measurement of energy per gallon of 200-proof ethanol.

The majority evaporator steam use is allocated to the distillation process because steam is recovered from the rectifier at a rate of 70% of input steam.

This process assumes a thermal oxidizer/heat recovery steam generator (TO/HRSG) combination. Natural gas use from the TO is not shown because HRSG uses waste heat reclaimed from the TO exhaust. Electrical energy for utilities is allocated over the total process.

Feedstock benchmarking

Feedstock benchmarking, or yield, is the number of products produced per bushel of corn. Generally, the following statements can be made about ethanol production from a corn kernel feedstock.

- Ethanol yield can rise or fall slightly with little variation in energy use.
- Distillers grain co-product yield is a trade off with the amount of the material converted to soluble products and ethanol.
- The water in corn is a function of the moisture content when utilized.

The largest factor to the energy and water usage benchmark numbers is the efficiency with which the plant utilizes the feedstock, or product yield. Below are the yields utilized for the base plant in this guidebook. Contact your Focus on Energy representative if your plant's yields vary and you would like an estimate of savings potential based upon product diversity at your plant.

Table 3: Benchmark yield

	FEEDSTOCK YIELD PER BUSHEL OF DRY CORN	50 MGY PLANT
200-proof ethanol	2.77 gal./bu.	5 million gal./yr.
WDGS (35% solids)	43 lbs./bu.	380,500 tons/yr.
DDGS (90% solids)	17.0 lbs./bu.	150,000 tons/yr.
Bushels of dry corn		17.7 million bu./yr.
Water (15.5% m.c.)	1.04 gal./bu.	18.4 million gal./yr.

The ethanol yield per bushel is the most critical KPI for a plant. The cost of the corn feedstock is the major expenditure for an ethanol plant and the sale of ethanol is the primary saleable product. A plant able to increase the ethanol yield per bushel will create more income at nearly the same input expense. Table 4 below shows the annual increase in yield and associated increase in gallons and sales receipts of ethanol.

Table 4: Effect of ethanol yield increase

Annual increase in yield (gal./bu.)	0.01 (2.68)	0.05 (2.72)	0.1 (2.77)
Annual increase in ethanol (gal.)	187,266	936,330	1,872,659
Annual increase in receipts ($)	$374,532	$1,872,659	$3,745,318

Assumed base = 2.67 gal./bu. producing 50 MGY and $2/gal. 200-proof ethanol

The profitability of the plant is also closely tied to the handling of the distillers grain co-product. There are many ways to handle the distillers grain and each can be profitable provided they are done efficiently. Distillers grain can be marketed and sold as:

- Wet distillers grain (WDG) – At the solid's outlet of the decanter.
- Wet distillers grain with solubles (WDGS) – At the outlet of the decanter with the condensed distiller's solubles.
- Dried distillers grain (DDG) – dried WDG.
- Dried distillers grain with solubles (DDGS) – dried WDGS.
- Modified distillers grain (MDG) – partially dried WDG.
- Modified distillers grain with solubles (MDGS) – partially dried WDGS.
- Syrup – The condensed distiller's solubles that originated from the decanter. This can only be sold in conjunction with WDG, MDG and DDG.

The process of drying the distillers grain is an energy-intensive process generally completed by thermal convection heating. Although as the product becomes more dried, it is less likely to spoil and gains value, resulting in similar income generation. For example, the typical energy to create 75% WDGS and 25% DDGS is 9,650 Btu/gal. of ethanol less than plants create 100% DDGS. The ultimate energy savings is contingent on the heat flow of an individual plant.

The syrup is created from the decanter condensate stream (solubles) after it is passed through an evaporator. The syrup contains nutrients that are valuable to most consumers of distiller's grain and therefore is regularly included in the product. It can also be sold individually with additional handling and storage systems.

Appendix C

Energy calculations and assumptions

Energy calculation – pre-process fractionation

The calculation below can be used to determine the impacts of implementing pre-process fractionation.

PRE-PROCESS FRACTIONATION PLANT CALCULATIONS		
Existing ethanol production (MGY)	50	
Annual feedstock (bu.)	18,000,000	
Construction costs	$550,000	
Additional cost of fractionation	$25,000,000	
Additional cost of corn oil extraction	$6,500,000	
Proposed ethanol production (MGY)	56	11% Increase
Proposed annual feedstock (bu.)	21,102,662	5% reduction in ethanol yield

PRODUCT SALES	COSTS (12/2008)	PRODUCTION RATE UNITS	PRODUCTION RATE	EXISTING CONDITIONS
Ethanol (gal)	$1.90	gal./bu.	2.78	$95,000,000
DDGS (ton)	$115	lb./bu.	17	$17,595,000
Total sales				**$112,595,000**

AFFECTED OPERATING EXPENSES	COSTS (12/2008)	RATE UNITS		EXISTING CONDITIONS
Feedstock (bu.)	$4.00	$/bu.		$72,000,000
Other raw materials (total)	$0.57	$/bu.		$10,260,000
Utilities (total)	$1.30	$/bu.		$23,400,000
Labor, supplies and overhead (total)	$0.26	$/bu.		$4,680,000
Total affected operating expenses				**$110,340,000**
Annual simple income				**$2,255,000**

			STD. FRACTIONATION		FRACTIONATION W/ CORN OIL	
PRODUCT SALES	COSTS (12/2008)	PRODUCTION RATE UNITS	PRODUCTION RATE	PROPOSED CONDITIONS	PRODUCTION RATE	PROPOSED CONDITIONS
Ethanol (gal)	$1.90	gal./bu.	2.63	$105,450,000	2.63	$105,450,000
DDGS (ton)	$115	lb./bu.	0.00	$0	0.00	$0
DDC-DDGS (ton)	$200	lb./bu.	11.00	$23,212,928	11.00	$23,212,928
Corn fiber (ton)	$75	lb./bu.	3.50	$2,769,724	3.50	$2,769,724
Corn germ (ton)	$130	lb./bu.	5.40	$7,407,034	0.00	$0
Corn oil (lb)	$0.30	lb./bu.	0.00	$0	0.86	$5,444,487
De-oiled corn germ (ton)	$160	lb./bu.	0.00	$0	4.50	$7,596,958
Total sales				**$138,839,686**		**$144,474,097**

AFFECTED OPERATING EXPENSES						
Feedstock (bu.)	$4.00			$84,410,646		$84,410,646
Other raw materials (total)	0.57	$/bu.	+ 1%	$12,148,802	+ 1%	$12,148,802
Utilities (total)	1.30	$/bu.	+ 20%	$28,080,000	+ 22%	$28,548,000
Labor, supplies and overhead (total)	0.26	$/bu.	- 11%	$4,883,156	- 10%	$4,938,023
Total affected operating expenses				**$129,522,605**		**$130,045,471**
Annual simple income				**$9,317,082**		**$14,428,625**
Annual income increase				**$7,062,082**		**$12,173,625**
Estimated capital cost				**$25,000,000**		**$31,500,000**
Payback period				**3.5**		**2.6**

Calculation assumptions

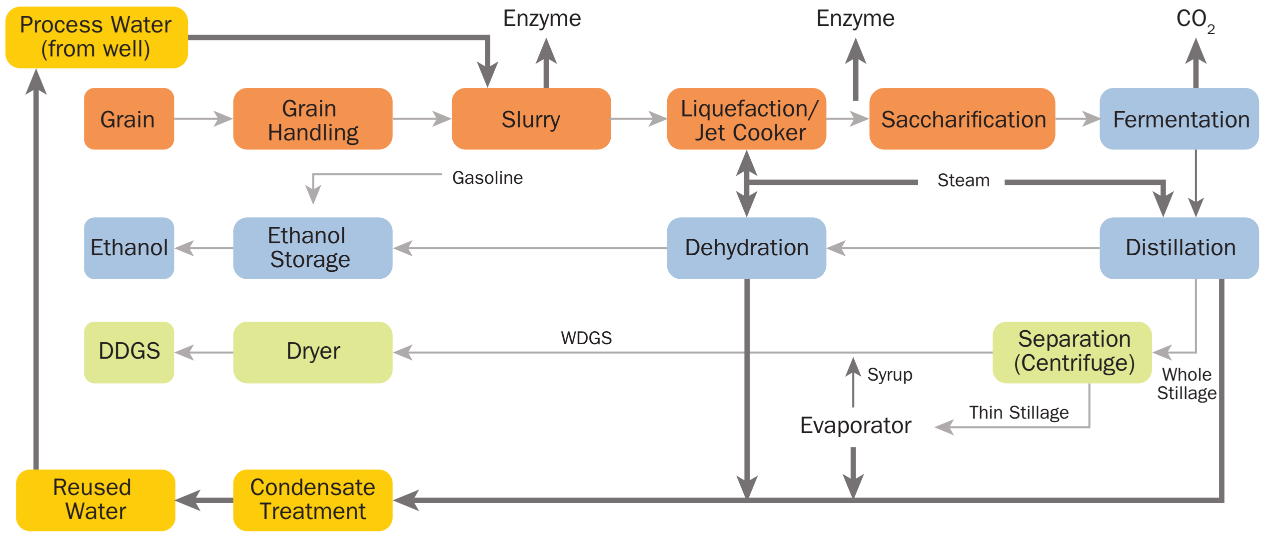
The assumptions below are used for the calculations in this guidebook. They are based upon typical prices. Contact your Focus on Energy representative if you would like the calculations completed based upon a different set of assumptions.

Table 5: Calculation assumptions

Yearly hours of operation	8,300 hours	**Water – well or municipal**	$ 2.00/1,000 gallon
Annual plant production	50 MGY 200-proof ethanol	**Water – wastewater**	$ 3.00/1,000 gallon
Annual yield	2.70 gal./bu.	**Corn**	$ 4.50/bu.
Annual feedstock	18.5 million bu.	**Ethanol**	$ 2.00/gallon
Electricity cost	$0.06/kWh	**DDGS**	$ 105.00/ton
Electricity peak cost	$200/kW (per year)	**WDG**	$ 33.60/ton
Natural gas	$0.35/therm		

Appendix D

Corn-based ethanol process diagram



Resources

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2. American Coalition on Renewable Energy – http://www.acore.org/
3. Corn Refiners Association – http://www.corn.org/
4. Governor's Ethanol Coalition – http://www.ethanol-gec.org/
5. International Ethanol Trade Association – http://www.ietha.org/ethanol/index.php
6. National Corn Growers Association – http://www.ncga.com/index.asp
7. National Ethanol Vehicle Coalition – http://www.e85fuel.com
8. Renewable Fuels Association – http://www.ethanolrfa.org/
9. Wisconsin Bio Industry Alliance – http://www.wisconsinbioindustry.com/
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16. U.S. Dept. of Energy Regional CHP Application Centers and ITP program for industrial distributed energy.
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