

**LAW OF BIOFUELS**  
**—Siting and Permitting Projects—**

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The growing interest in biofuels as a viable alternative to traditional energy and fuel sources has spurred a flurry of biofuels production facility development and construction. In addition, many developers are adding a biofuels production component to an existing enterprise by retooling or expanding pulp and paper mills, corn milling facilities, vegetable oil refineries, landfills, and other plants or factories to maximize waste or byproducts. Both strategies have advantages in terms of project design and implementation of new technologies within the production facility. But on the ground, the siting and permitting of biofuels projects requires careful consideration of local land use laws, access to transportation for feedstock and delivery of product to market, water use and discharge requirements, and air quality rules that may impose significant design and production constraints.

In this heady climate of rapid growth in biofuels, prudent developers can achieve a significant advantage in bringing their projects online by taking a disciplined approach to siting and permitting—by conducting a thorough inquiry into land use, environmental and transportation requirements, a feedstock and market access analysis, and consulting with interested agencies, communities and interest groups to ensure seamless development and operation of a project.

## **I. LOCATION, LOCATION, LOCATION: KEY ISSUES IN SITE SELECTION**

Selecting a project site or expanding an existing facility requires analysis of feedstock availability, transportation requirements for feedstock and product distribution, and local and state land use restrictions. Factors such as the need for rail lines or access roads, facility and equipment size and location, land ownership and federal involvement may determine the number of agencies and the level of governmental involvement in a particular project.

### **A. Access to Feedstock**

Evaluating a proposed biofuels project site starts with assessing the site's access to feedstock—the agricultural or organic matter to be converted into fuel. Proximity to feedstock drives site selection because the closer the feedstock is to a facility, the lower the production costs. Innovations in converting organic matter, poultry waste, vegetable oils, and other consumer waste and manufacturing byproducts into biofuels provide an incentive to enhance or expand existing manufacturing facilities to add a biofuels-production component to make use of readily available feedstock. In the absence of on-site feedstock, developers must consider the amount of feedstock required to produce an economically feasible amount of biofuels and whether transportation costs are low enough to maintain profitability. For example, most modern ethanol plants constructed in the Midwest have a capacity of 30 to 40 million gallons a year (mgy), requiring approximately 11 to 14 million bushels of corn a year. Consequently, any production facility constructed to produce 30 to 40 mgy will require local feedstock or low transportation costs to be economically feasible. Using grain trucks to deliver feedstock for a 30 mgy ethanol project would require delivery by approximately six grain trucks a day. Coastal or river sites may take advantage of foreign feedstocks shipped by cargo vessels. Whatever type of site is selected, careful consideration should be given to access to feedstock and the costs of handling and transporting feedstock.

### **B. Transportation to End Markets**

Delivering biofuels to end markets in a cost-effective and efficient manner is similarly critical to profitability. Site selection should be based not only on proximity to feedstock but also on railroad and highway access to

markets. Any projects co-located with existing agricultural, milling or other operations should give careful consideration to easements and access required for the delivery of product to end markets. If property is leased or if a co-located project is later separated and sold from the primary manufacturing operation, the project developer will want to ensure all necessary road and public highway easements and railroad lines are available for the biofuels project to operate independently.

In addition, developers of ethanol projects will want to consider the proximity to the distillers grain market. Most Midwestern ethanol plants dry the distillers wet grain—the solid portion of stillage remaining from the distilling process—and sell the dry grain as dairy feed. Wet distillers grain must be sold for dairy feed within five days or it will rot. To ensure sufficient time to market, transportation or reuse of distillers grain should be considered as part of the transportation analysis conducted during the site selection process.

### **C. Energy and Utilities**

Siting a biofuels project requires access to energy—usually natural gas. When considering potential sites, developers should consider whether existing pipelines and easements are in place and, if energy transmission facilities are not in place, what types of permits, licenses and easements may be required to bring energy to the facility. Similarly, electricity, water supply and wastewater connections will be required for virtually all types of biofuels projects. Selecting a location with ready access to water, existing electricity connections and a means of disposing of wastewater is critical. For example, ethanol production facilities that do not dry the residual distillers grain require approximately 25,000 BTU of heat and 1.1 kWh of power (electricity) per gallon produced. Distributed (on-site) power generation systems allow for greater energy production and insulate a project from local electricity failures. Development of a cogeneration system may also trigger additional permitting requirements that should be determined during site selection. Permits, licenses or agreements with local utilities may be required and should be investigated prior to site selection.

### **D. Rail**

A project in the Midwest was recently derailed by the project proponent's failure to locate the project near a railroad line that could accommodate the trains needed to deliver grain to the project. Although the railroad told the developer and city officials that its railroad spur into an industrial tract could not handle the trains needed to deliver grain to the plant, the developer continued planning construction of the \$140 million plant. A senior business manager from Union Pacific told a local newspaper that the days of saying "this is my site and bring the rail here" are over. The developers spent months planning the project before the railroad's position was brought to bear: Union Pacific was not interested in spending \$2 million to \$3 million to upgrade the spur. The story provides a good lesson for developers that intend to rely on existing railroad tracks for feedstock delivery. An inquiry should be made to ensure rail access is available and that the railroad can handle the traffic and loads required for the project.

## **II. SITING AND PERMITTING**

### **A. The Regulatory Energy Facility Siting Process**

*State Siting.* Although siting approval of biofuels projects is generally subject to local jurisdiction, some states, such as Washington, Oregon and Minnesota, have state energy facility siting councils or boards that have

jurisdiction over all energy facility siting decisions in the state where the capacity of the energy facility meets or exceeds a certain size. For example, in Oregon, biofuels projects with a capacity of approximately 18.6 mgy or more are subject to the “one-stop” jurisdiction of the Oregon Energy Facility Siting Council. Biofuels projects may be of sufficient capacity to fall within the jurisdiction of such a siting council, which typically preempt local siting authority. Consequently, the jurisdiction over a potential project should be determined during the site selection process.

*Local Siting.* If a project falls below the jurisdiction threshold, or if a proposed project is located in a state that does not have “one-stop” state siting jurisdiction or that simply does not have any siting process for biofuels projects, the siting process will be subject to local jurisdiction, which, for many biofuels projects that are co-located with agricultural operations, is almost always a county as opposed to a city governing body.

*Comparative Advantages.* Generally, siting a large-scale biofuels facility through a state siting process takes longer than siting through a local process because more documentation is typically required at the state level. For example, in Oregon, the issuance of a site certificate for a biofuels project may take 12 months or more. In comparison, siting at the local level may be completed in three to six months if no significant environmental reviews are required.

## **B. Permitting**

Land use and environmental permitting issues should be reviewed by developers early in the project planning process, because of their potential to affect location and design decisions. The complexity of permitting and the length of time required to fully permit a facility can have significant impacts on the construction times, design and eventual viability of a facility. It is advisable that early on in project planning, along with a Phase I environmental analysis, a land use analysis should be completed. These types of issues are magnified in California and other states with environmental planning requirements and on federal land where the permits require in depth environmental review.

## **C. Land Use**

*Local Land Use Issues.* Many cities and counties have traditional zoning codes or ordinances designating appropriate uses based on complying with overarching planning documents such as general plans. These zoning codes dictate the types of uses and densities that are allowed without a permit (by right) in particular districts. The codes in many instances also allow projects that are not generally allowed by right to be permitted under a Special Use Permit (SUP) or Conditional Use Permit (CUP). Many zoning districts may prohibit certain types of uses altogether, such as industrial uses in residential areas. Limitations in the general plans may also affect the siting of a project if the project is inconsistent with the policies thereon. Additional issues such as easements, encroachments and the like should also be reviewed to ensure that they do not impact operations.

*Conditional Use Permit/Special Use Permit.* CUPs or SUPs allow for “semi-compatible” uses to be approved by requiring conditions that make the project more compatible with the existing uses in that area. CUPs or SUPs in many jurisdictions will require a much more rigorous public review and comment period. Issuance of a CUP or SUP may trigger local environmental review requirements (see below).

*Zoning Restrictions.* Most zoning codes also mandate certain building restrictions that relate to height, set-backs and the like that may affect the operations or design. Usually a procedure exists whereby a project applicant can obtain a variance to exempt compliance with such restrictions upon a finding of good cause. Issuance of a zoning variance may trigger local environmental review requirements (see below).

*General Plan or Location Amendments/Ordinance Requirements.* If a project encounters major zoning restrictions, it may require that more basic underlying planning documents, such as general plans, need to be amended. For instance, if a plant attempts to locate a particular site that does not allow for that use by right or by special or conditional use permit, a general plan amendment might be required to change the zoning. In many localities, such a discretionary action requires a comprehensive environmental review.

*Subdivision Map Act.* Some states, such as California, regulate the organization of subdivision maps and parcels maps. Any enlargement or carving out of parcels may require compliance with this act.

*Agricultural Preserves.* In many states there are rules or statutes in place to prohibit the conversion of agricultural land to nonagricultural purposes. For example, in California, certain properties have been set aside as agricultural preserves under the Williamson Act and are subject to certain tax benefits if the use remains an agriculture or “agriculturally compatible” use. In one facility, the county found that ethanol plants are not compatible with the Williamson Act and required an additional discretionary approval. A penalty payment is usually required to remove a property from this act and to cancel the contract between the owner and the public agency that originally required the land to be set aside.

*Urban Encroachment.* Because of potential odor issues, noise and other aesthetic issues, an examination of the potential for encroachment of urban uses is a necessity.

*Traffic.* One impact that may be reviewed by a permitting agency is the stress or additional stress a project may have on traffic or specific roadways. If traffic will affect a roadway beyond the existing standard for a particular roadway, as part of the approval process, an applicant may have to make extensive upgrades to the roadway.

*Noise.* Noise is an issue that is reviewed with regard to use permits and/or local ordinances concerning maximum noise levels and hours of operation. It is common to have restrictions upon operating hours to avoid noise issues. Restrictions on the operating period may affect the potential economics of a plant.

#### **D. Environmental Permitting**

As with most industrial facilities, an Environmental Site Assessment (referred to as an ESA or Phase I report) is generally required prior to purchase or lease of real property. Performing an ESA is prudent in order to protect a buyer from liability for hazardous materials, and, more importantly, to determine if there are any environmental issues (such as underground tanks and the like) that may affect the value or use of the property. It is the rare (and foolish) lender that would ever hand over money without first reviewing an ESA. The U.S. Environmental Protection Agency (EPA) recently adopted new minimum ESA standards. These standards require more extensive procedures and technical experience, with the result that Phase I studies are now more expensive. Other environmental issues reviewed may include the distance to the nearest receptors and investigation into neighboring properties that have environmental issues that may impact the project.

*Water Supply.* Water supply for a plant is crucial. In many areas water is available from wells, surface water sources or in the alternative from a public water system. The choice of supply may affect major costs for the supply of water. For example, one plant in Sacramento with contaminated wells went from costs for pumping ranging to several thousand dollars to annual costs of water from a local system of \$200,000 to \$300,000 per year. As water becomes scarcer, the ability to obtain a water right authorizing the withdrawal of surface or groundwater is becoming increasingly challenging. A biofuels facility developer should never assume that a water right associated with a non-industrial use can necessarily be transferred to the biofuels facility. Similarly, a developer cannot assume that groundwater wells can be drilled so as to provide process water. For example, the development of a plant in Texas was affected when a local groundwater conservation district implemented rules requiring permitting of groundwater wells between the time the developer moved ahead and the time the financing occurred. The lack of the groundwater permit caused an awkward, although curable, issue and associated delay in the financing, which could have been avoided had the developer been more focused on groundwater permit requirements. A thorough review of water rights is an essential aspect of commencing the development or purchase of any biofuels project.

The chemical makeup of the water supply may also be an issue: the water must meet both the purposes for use of water and for eventual disposal. For instance, in areas with volcanic soils, use of water containing natural arsenic may result in concentration of the metals; these metals make disposal or reuse of the wastewater more difficult, potentially affecting design issues and disposal costs. In some instances, wastewater with minimal contaminants can be evaporated in adequate ponds. In some areas, the wastewater may need to be disposed of more formally. The energy costs for pumping or transporting well or surface water must be taken into account and in instances of more rural facilities.

*Water Discharge.* In many states, any discharge with the potential to affect groundwater is required to be permitted. The permitting authority can range from the state environmental agency to a regional water quality control board. This requirement can extend to seepage ponds as well as land application (sprinkling) systems. Discharge to dry wells or other receptacles that are deeper than they are wide potentially requires separate permitting as underground injection wells. When the wastewater discharge is to a surface impoundment or sprinkling system and that discharge has the potential to impact surface waters, then that discharge may have to be permitted as a surface water discharge.

If a project will discharge effluent (including stormwater) to surface water, a National Point Discharge Elimination System (NPDES) permit will be required in most instances. This permit will be issued either by the local permitting authority under a delegation agreement with EPA or directly by EPA if no delegation agreement exists (e.g., most Indian reservations). This permit may fit within the terms of a general permit (such as for stormwater), in which case permit coverage can be assigned just by asking. However, if the discharge is not within the terms of a general permit, an individual NPDES permit must be obtained. In most jurisdictions, obtaining an individual NPDES permit is a lengthy undertaking.

An option taken by some biofuels facilities is to discharge to the local publicly owned treatment works (POTW) via a sewer connection. If a biofuels plant wants to discharge to a POTW, then an industrial pretreatment agreement or permit may be required. The volume and characteristics of the wastewater will help determine this requirement. The pretreatment agreement or permit identifies the level of pretreatment required of the facility and the quantity of wastewater it may send to the POTW. Limits are designed to prevent a discharge from

interfering with effective POTW operation or passing wastewater through the POTW in amounts detrimental to fish and other aquatic life. Although discharging to a POTW may be a viable means of disposing of wastewater, it potentially leaves the biofuels facility open to system development charges, increasing discharge fees over time and the vagaries of a system influenced by the local politicians in office at the time.

*Wildlife/Vegetation/Historical Resources.* As with any other projects that may be constructed in undeveloped areas, it is usually necessary to conduct a survey to determine whether any protected wildlife or vegetation will be affected. Certain areas may have to be surveyed and any wetlands identified. In some instances, historical uses and/or paleontologic resources must be reviewed. The earlier these issues are identified, the more easily they can be addressed. The agencies raising these issues often believe they have much more authority than they actually have. We worked on a facility where the requirement to assess impacts to fossils was triggered and the lead agency initially required permanent ongoing obligations for the life of the plant. After some friendly discussions regarding the agency's actual authority, all future requirements were dropped and a much simpler construction plan was required.

*Enhanced Environmental Review: NEPA/Mini-NEPA.* Prior to any discretionary federal agency action, the agency must consider how to comply with the National Environmental Policy Act (NEPA). If the intended action is found to be a major action with significant environmental impacts, then an Environmental Impact Statement (EIS) is required. NEPA does not authorize the agency action, it simply forms the environmental basis for the agency action. The NEPA process is most frequently triggered when a project is located on federal or tribal land or involves significant federal resources. NEPA does not apply to actions by state agencies. However, approximately 20 states have implemented "mini-NEPA" statutes that create similar state agency responsibilities. For example, California has the California Environmental Quality Act (CEQA), which is triggered by discretionary approvals by governmental agencies, including the local agencies that have an approval related to that project. Thus any permit approvals including use permits, waste discharge permits and the like are potentially subject to CEQA. Under CEQA, the lead agency examines the application and drafts an initial study to identify potential significant impacts. If the impacts can be mitigated, a shorter Negative Declaration can be drafted. If there is the potential for significant environmental impacts, a more comprehensive Environmental Impact Report (EIR) is required. One of the more difficult issues addressed in an EIR may include the cumulative impacts of the project (an especially difficult issue in areas, such as California's Central Valley, where air quality standards are not being met). Other difficult issues include alternatives, and whether the agency can conclude that the benefits of the project outweigh the potential for a determination of environmental impacts. More recent issues that have arisen with regard to biofuels plants include water use, odor and the extent of volatile organic compound (VOC) emissions and how to measure and control them.

*Timing.* Additional permitting issues may affect the schedule of a project. In order to develop a project-specific assessment of issues that may cause permitting delay, consider whether any of the following apply:

- Compatible zoning
- SUP
- The scope of NEPA or mini-NEPA environmental review
- The time it will take to process permits and air and water discharge permits

In addition to these considerations, following is a nonexclusive list of additional potential “environmental” permits that may be required:

- Spill-prevention control and countermeasures plan
- Plan for chemical storage areas, inventories for the handling of hazardous chemicals, state and federal requirements
- OSHA and/or MSDS recordkeeping
- Above- or below-ground storage tank permits, possibly including secondary containment or leak detection
- Bureau of Alcohol, Tobacco and Firearms plan
- OSHA boiler license
- Risk management prevention plan

#### **E. Air Permitting**

Air permits are often the most complicated permits to obtain for biofuels production facilities. Everything from the choice of biodiesel feedstocks to whether an ethanol plant’s distillers grain will be sold dry or wet can have a fundamental impact on the permitting of a new or modified facility. In addition, local air permitting requirements can be more stringent than the federal permit requirements, resulting in a significant disparity in the air permitting burden between identical plants located in different states or even different parts of the same state. This summary identifies key air permitting considerations; however, developers must consult with qualified air permitting professionals to ensure compliance with all local permitting requirements in advance of purchasing or installing any equipment.

*Requirement to Obtain a Construction Permit.* Federal law categorizes every area of the country according to the levels of primary air pollutants (referred to as criteria pollutants) in that area’s air. The EPA identifies those areas of the country that do not meet the ambient air quality standards for a particular criteria pollutant as “nonattainment areas.” Nonattainment designations are pollutant specific; consequently, an area might be “nonattainment” for ozone, one of the criteria pollutants, but still be considered “attainment” for particulate, sulfur dioxide, carbon monoxide and/or lead. Locating a biofuels plant in a nonattainment area typically increases the regulatory burden and permitting time because permitting thresholds are lower in nonattainment areas and the requirements more stringent. Areas other than nonattainment areas are considered attainment areas or unclassifiable areas. Because facilities slated for construction in attainment areas are treated the same as sources planning to locate in unclassifiable areas, both area types are regarded as attainment areas.

For the purpose of air permitting, biofuels facilities are deemed “sources” because each facility is a source of air pollutants. Sources located in an attainment area are potentially subject to one of two types of permitting programs. Smaller sources of air pollutants are typically permitted under local permitting programs referred to as “minor new source review.” The trigger thresholds for these programs vary considerably, as do the requirements for emissions controls, once triggered. Typically, but not always, the applicability of these programs depends on the facility’s potential to emit. Potential to emit is determined for each pollutant based on the assumption that the facility will operate 24 hours a day, 365 days a year. As part of the permit, limitations can usually be assumed

to constrain operations below a given threshold, thereby decreasing the potential to emit. For example, if a developer designs a plant to operate 340 days per year, a permit condition could specify that limit on hours/days of operation. If this limit is sufficient to drop the facility below an applicable threshold, taking on this “synthetic minor” limit may be an appropriate business decision. Often, biofuels facilities will take limits on production (for example, an ethanol plant will limit its production to 90 mg-y) to avoid certain permitting responsibilities. It is unusual for a commercial-scale biofuels facility to avoid all air permitting requirements by taking on limits, but it is not uncommon for facilities to take on limits to avoid major new source review.

Sources located in attainment areas are subject to major new source review if their potential to emit (after taking into account federally enforceable limitations) is greater than certain thresholds. In most parts of the country, the threshold for triggering major new source review is the emission of 100 tons per year of any regulated air pollutant if the facility is identified as within a federally designated source category, or 250 tons per year if the facility is not in one of the federally designated source categories. “Chemical process plant” is a federally designated source category. In 1981, EPA concluded that the manufacturing of ethanol for use as fuel was a chemical process and therefore classified ethanol plants as chemical process plants. Consequently, as a matter of federal law, any fuel ethanol production plant that has the potential to emit 100 tons per year or more of any regulated air pollutant triggers what is known as “federal attainment area major new source review”—also commonly referred to as the Prevention of Significant Deterioration (PSD) program.

Permitting a new or modified facility under the PSD program is a major regulatory undertaking that often takes a year or more to accomplish. Because of EPA’s categorization of ethanol fuel plants as “chemical process plants,” most fuel ethanol plants have taken production limits that ensure they do not trigger PSD. This has significantly curtailed the size of ethanol plants, without any material environmental benefit. Paradoxically, if an identical plant manufactured ethanol for food and beverage purposes, it is not considered a chemical plant and so therefore was subject to the 250 ton per year PSD threshold.

Recognizing the inequity of the rule, in March 2006 EPA proposed exempting wet and dry corn milling facilities that produce ethanol fuel from the definition of “chemical process plants.” If this rule becomes final as proposed, facilities using corn (but not other starches) as feedstock would not trigger PSD unless they have a potential to emit 250 tons per year or more of any regulated air pollutant. In essence, corn-based ethanol plants could be 2.5 times larger than currently possible and not trigger PSD review. Action on this proposed rulemaking is unlikely until at least 2007.

Sources subject to PSD must comply with specific requirements. The most significant of these are (1) the requirement to perform modeling to demonstrate compliance with ambient air quality standards and air quality increment requirements, (2) the requirement, unless exempted, to perform a year of preconstruction monitoring, and (3) the requirement to install best available control technology (BACT). Many, but not all, state minor new source review programs require one or more of these elements even if the source does not trigger PSD. However, the stringency with which these requirements are applied and the degree of public scrutiny and involvement is often much greater when a source is subject to PSD. In addition, in many states EPA is either the lead or a co-permitting authority when PSD is triggered. This federal scrutiny may also increase the time to permit a source.

Sources slated for construction and operation in nonattainment areas that have the potential to emit more than the threshold levels of the nonattainment pollutant or pollutants are subject to the most stringent air permitting requirements. Most significantly, biofuels facilities triggering nonattainment new source review must provide offsets (emission reduction credits) at least equal to their total emissions. In some areas, sources triggering nonattainment new source review must provide emission reduction credits equal to as much as 150 percent of their potential to emit. This increases cost and may render projects infeasible because emission reduction credits simply are not available. In addition, sources triggering nonattainment new source review must use controls that are considered to result in the “lowest achievable emission rate.” This level of control, referred to as “LAER” (pronounced like “layer”), requires the highest level of control achieved anywhere in the ethanol industry or in similar industries in which the technology is considered transferable. Most importantly, cost is not considered when establishing LAER (in marked contrast to BACT, for which economic, energy and environmental impacts are considered). The requirement for emission reduction credits and LAER often are significant incentives to maintain facilities at the lowest emission levels possible—to stay below nonattainment new source review thresholds.

Whether a source is being permitted under nonattainment new source review, PSD or local minor new source review, it is important to understand that these are preconstruction permitting programs. Facility construction is not authorized to proceed until a construction permit is issued under the applicable air-permitting regime. EPA has authorized land clearing and grading, but in guidance documents the agency has suggested that if an air permit has not been obtained, any work beyond clearing and grading is illegal. Some local permitting authorities have allowed certain work beyond clearing and grading in advance of receipt of a permit. However, a developer should consult with an attorney specifically experienced in air permitting before assuming that any work beyond land clearing will be tolerated in advance of receiving the permit.

A common compliance issue arises when, after receiving an air permit authorizing construction of a source, contractors decide to modify the design of a facility. Air permitting authorities are literal folks, and they typically demand that a plant be constructed and operated exactly as described in the permit application. Thus, when a permit authorizes a 75 MMBtu/hour boiler, the permitting authority will not be pleased when the contractor substitutes a 90 MMBtu/hour boiler. The permitting authority typically does not care that a developer intends to operate the boiler at 75 MMBtu/hr—the agency authorized a particular size unit and it will expect the developer to build the unit as permitted or to modify the permit.

*Federal Operating Permits (Title V).* In addition to new source review, other air permitting requirements may apply to biofuels plants. In many states, the new source review permit is merely a construction permit—that is, the permit authorizes construction of a facility as specifically identified in the permit. The source is required to obtain an operating permit in addition to the construction permit, or convert the construction permit into an operating permit after demonstrating compliance with all requirements. In addition, if the plant has the potential to emit 100 tons per year or more of any regulated air pollutant, 10 tons per year of any individual hazardous air pollutant, or 25 tons per year or more of aggregate hazardous air pollutants, it must obtain a federal operating permit, commonly referred to as a “Title V permit.” These thresholds may be lower in certain areas, but other criteria may trigger the need for a Title V permit. Although most states do not require an application for a Title V permit until the facility has operated for a year, some states require that a Title V application be submitted concurrent with a new source review permit application.

*New Source Performance Standards.* Federal law imposes specific standards called New Source Performance Standards (NSPS) on certain types of new, modified or reconstructed equipment. The NSPS include substantive standards (for example, particulate, NO<sub>x</sub> or SO<sub>2</sub> limits) and extensive notification, testing, monitoring, recordkeeping and reporting requirements. Several NSPS potentially apply to biofuels plants, including standards applicable to:

- Boilers with a nameplate heat input greater than 10 MMBtu/hour
- Volatile organic liquid storage vessels with a capacity greater than approximately 10,000 gallons
- Grain elevators with storage capacity of 1 million bushels or more
- Equipment leak standards applicable to synthetic organic chemical manufacturing plants (ethanol is defined as a covered chemical)

The standards are federal but have been adopted by most local permitting authorities, resulting in confusing overlapping jurisdiction. EPA has primary authority to issue notices and authorize exceptions to NSPS requirements—a fact often forgotten by local permitting authorities and consultants with sometimes unpleasant consequences for the biofuels plant.

It is frequently necessary to police the permitting agencies on how they apply the NSPS. We worked on one ethanol facility where the air permitting consultant and agency together made a wrong determination of how the NSPS applied that essentially made it illegal to operate the plant. This fact was not discovered until the plant had been operating for about nine months at which time we were brought in to help fix the situation. Penalties were assessed and the permits had to be changed. Early involvement of legal counsel knowledgeable in the nuances of air permitting law would have avoided this costly and embarrassing situation.

*Hazardous and Toxic Air Pollutants.* Under federal law, biofuels plants with the potential to emit 10 tons per year of any individual hazardous air pollutant or 25 tons per year or more of aggregate hazardous air pollutants are considered “major sources” of hazardous air pollutants. Consequently, the source must obtain a Title V federal operating permit. Of potentially much greater consequence, the source must also comply with the hazardous air pollutant general provisions, which, in part, impose notice and preconstruction review requirements, and the source must use maximum available control technology (MACT) to minimize hazardous air pollutant emissions. At most ethanol plants this involves compliance with the boiler MACT standards (which is negligible if the sole fuel is natural gas) and miscellaneous organic chemical production MACT standards. Not so long ago, ethanol plant operators assumed that they were unlikely to be major sources of hazardous air pollutants. However, as testing has become more sophisticated, the industry has learned that several hazardous air pollutants are potentially emitted in significant quantities from previously unsuspected sources. Therefore, careful consideration early in the development process of the applicability of the MACT requirements is critical.

Many local permitting authorities have air toxics programs that exceed the federal hazardous air pollutant program with respect to the number of pollutants covered and the preconstruction modeling and assessment required. State and federal interest in the impact of air toxics has increased substantially in recent years.

*Odor.* A frequent concern raised by residents living near a proposed biofuels facility is odor. Virtually all areas have rules prohibiting a facility from causing a nuisance. Even if such rules are not on the books, a nuisance

lawsuit alleging the facility is unreasonably interfering with the neighbors' right to enjoy their lives free of excessive odors is always a possibility. The public and the permitting agencies frequently think the standard is no odor. However, in most jurisdictions, the true legal requirement is that the facility not create an unreasonable amount or intensity of odor. Local regulations often require the development of an odor abatement plan—particularly if complaints have been filed—and doing so may provide some level of protection against nuisance suits. Although all 50 states have some variation of a “right-to-farm” statute protecting agricultural operations from odor lawsuits, these statutes are typically construed narrowly. Local precedent must be consulted to determine whether these statutes could provide relief for any portion of a biofuel operation. As residential development creeps closer to industrial and agricultural development, increased capital is being applied to minimize the likelihood of odors. Nonetheless, any industrial operation still retains some potential for odors, so this aspect must be considered in siting and permitting a new or expanded facility. Notwithstanding the best of planning, you can still run afoul of odor issues if you do not exercise constant vigilance. We assisted one facility that was located next to a hog farm—a location that the developer believed insulated it from odor complaints. While the plant was being constructed, a local builder bought the farm, obtained a land use variance and built high end homes. Once operation began, the complaints started pouring in, followed shortly thereafter by lawsuits. Although we managed a favorable settlement, intervention in the hog farm’s variance hearing would have saved much more expense later on.

*Greenhouse Gases.* Carbon dioxide (CO<sub>2</sub>) emitted from ethanol plants is not currently regulated at the federal level. However, increasing local interest is driving voluntary and, more recently, involuntary efforts to reduce CO<sub>2</sub> emissions due to concerns about global warming. Compared to other pollutants, CO<sub>2</sub> is not a particularly potent greenhouse gas, but it is emitted in large quantities by combustion sources, as well as ethanol plants. Some ethanol plants capture much of their CO<sub>2</sub> and manage it as a byproduct, but the practice is by no means universal. Increasing regulatory scrutiny of CO<sub>2</sub> emissions is anticipated in the near future.

In deciding how to proceed with new source review permitting, it is critical that developers and their respective permitting authority understand up front what the potential emissions from the facility might be. Biofuels facilities that use technical or legal assistance unfamiliar with the equipment and processes or the way the agencies regulate the equipment and processes have experienced traumatic results from financing delays to enforcement. There has been growing understanding in recent years of air emissions from certain biofuels manufacturing processes that previously were thought to have little or no emissions. To assess these emissions and counsel developers and plants on how to address them requires both experience with biofuels plants and the subtleties of air regulations.