GUIDE FOR SITING SMALL-SCALE BIOMASS PROJECTS IN NEW YORK STATE

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NEW YORK STATE
ENERGY RESEARCH AND
DEVELOPMENT AUTHORITY

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Guide for Siting Small-Scale Biomass Projects in New York State

Final Report

Prepared for the

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NOTICE

Abstract

New York State has an abundant supply of biomass resources that, if used effectively, could help the state meet both its electricity supply needs and its environmental goals. By 2013, according to the state's renewable portfolio standard (RPS), 25% of electric generation should come from renewable resources. Encouraging small, biomass-based distributed generation would help the state meet this goal, while reducing greenhouse gas emissions and dependence on fossil fuels, increasing grid stability, and stimulating local economies. However, developers of small biomass projects face many informational barriers. They must select the most advantageous fuels and technologies, navigate complex permitting requirements, and secure financing. NYSERDA commissioned this guidebook to assist developers of small biomass-fueled electricity generation plants (less than 10 MW) in overcoming these barriers. The Guidebook focuses on three technologies: agricultural waste biogas (anaerobic digesters), biomass direct fire or co-fire facilities, and biomass gasification. These technologies were selected based on their viability and potential for development in New York State.

Keywords

Agricultural digester
Biomass
Co-fire
Development
Feedstocks
Gasification
Guidebook
Manure management

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EXECUTIVE SUMMARY

This *Guide for Siting Small-Scale Biomass Projects in New York State* provides an introduction to developing three types of small to midsized biomass-fueled electricity generation plants (that is, facilities under 10 MW in generating capacity). The guidebook is intended to help the reader understand and navigate the key steps and important issues, from project design to installation and operation.

Development of small to midsized renewable energy projects can be challenging. Smaller-scale facilities often have fewer technical and financial resources to analyze and take advantage of renewable power development opportunities. Information gathering costs can be significant in the areas of project development, permitting, and compliance; and potential developers of these projects may be deterred by the complex and confusing issues involved. The small outputs of these projects make them more sensitive to capital costs as well as the costs of a prolonged permitting process. This guidebook seeks to address these issues by providing an informational resource.

The New York State Energy Research and Development Authority sponsored the production of this guidebook to support the development of economically viable and environmentally appropriate small-to-midsized biomass fueled electric generation facilities in New York. In many parts of New York, there are abundant and available supplies of biomass resources. If used effectively, these resources can help the state meet its electricity needs while simultaneously supporting its environmental goals; that is, improving air and water quality and reducing New York's contribution to climate change.

The three types of biomass-fueled electricity-generating technologies covered in this guidebook are:

1. Agricultural Digester
2. Biomass Direct Fire or Co-fire
3. Biomass Gasification

The key steps of the project development process covered in this guidebook include:

- Project design and site selection
- Technology characteristics and selection
- Feedstock and fuel characteristics, processing requirements and availability[1]
- Project economics, costs and benefits
- Project financing
- Environmental and local permitting

The guidebook provides potential project developers an outline of the issues they should address, the information they should analyze, the permits they should plan to obtain, and the project management steps they should take to develop a project effectively, with regard to the above key steps.

Guidebook Organization

The guidebook has three important components:

1. An introduction to project financing, permitting and environmental compliance, and energy offtake issues. These are key crosscutting issues that every biomass project will face. These issues are covered in Chapters 1, 2 and 3.
2. Three technology focused chapters addressing the key elements necessary for the development of each of the three technologies covered in this guidebook: Agricultural Waste Digesters (Chapter 4), Direct Biomass Combustion and Co-firing (Chapter 5), and Biomass Gasification (Chapter 6).

[1] For the purposes of this guidebook, the term "feedstocks" refers to raw resources such as crop residues, energy crops, trees, waste materials, etc., while "fuels" are processed to some degree (i.e. comminution, drying, or other pretreatment). Thus, forestry trimmings are a feedstock, while wood chips are a fuel.

3. Appendices. Detailed information on environmental regulations, point-source and life cycle emissions of selected technologies and operating systems, biomass feedstock resources, and the like are contained in the Appendices.

CHAPTER 1 – CROSSCUTTING ISSUES: ENVIRONMENTAL REGULATIONS AND PERMITTING

1.1-INTRODUCTION

Proposed biomass projects in New York State will be subject to numerous environmental regulations and permitting requirements. Many of these requirements will be similar to those faced by more established fossil fuel-based generators. However, biomass projects may face additional hurdles due to the relative newness of the technology. Because such projects are not commonplace in New York (or in most other states), regulatory agencies are likely to have little experience upon which to base decisions. In addition, existing regulations may not address every element of a proposed development. For these reasons, developers should anticipate that the permitting process may take longer for biomass projects than for other technologies with which regulatory and permitting bodies may be more familiar.

This section of the guidebook is intended as a starting point for New York State biomass developers in evaluating the regulatory and environmental issues associated with small to midsized projects. It is not a cookbook, but rather a guidance document to be used in conjunction with other available resources and with assistance from environmental regulators and professionals. For more information on possible environmental impacts and the environmental review framework for biomass projects in New York State, see Appendix 1 – Environmental Compliance.

1.2 THE REGULATORY LANDSCAPE

While each proposed biomass project will be unique, each will face standard regulatory and permitting requirements at the state, regional and federal levels. For example, projects will be subject to the State Environmental Quality Review (SEQR). Additional requirements may be imposed by the New York State Department of Environmental Conservation (NYSDEC) and, if the project falls within New York City's jurisdiction, including upstate areas within the city watershed, it will be subject to requirements of the New York City Department of Environmental Protection. Federal regulations, such as those administered by the Environmental Protection Agency, will also apply. Information on these various agencies and their regulatory requirements is widely available and is not repeated in great detail in this guidebook.

The "wild card" for developers in New York State will most likely be the regulatory and permitting requirements of the local municipality. New York is a "home-rule" state, meaning land use regulation is largely within the jurisdiction of local municipalities (towns, cities, villages and hamlets). Thus, at the most basic level, project development in New York is governed by a patchwork quilt of zoning ordinances and comprehensive plans, which can vary widely from one municipality to another. In addition, local municipal boards traditionally (though not invariably) assume "lead agency" status in the SEQR process. Due to this regulatory complexity, a single approach to planning will not work for all projects within the State. Instead, each project must be individually planned to comply with the requirements set by the municipality or municipalities within which it lies.

The prominence of the local municipality in land use regulation and permitting points to the importance of establishing positive relationships with local agencies, officials and residents, who will have significant input into the environmental assessment and permitting process. This cannot be overstated: gaining local support is a crucial part of the permitting process. Many projects have been defeated by public opposition. Therefore, it is advisable to consult local boards and permitting agencies, and to inform the public about the project, as early as possible in the development process. Surprising local residents with a fully-developed project is not likely to engender a spirit of trust and confidence. Additionally, the developer may save both time and money by addressing issues of contention early, thus avoiding the need to revise detailed development plans later in the process.

The trust and good will of community residents and neighboring businesses will not only help a project through the permitting process, but will be an important asset to the project throughout its lifespan.

1.3 NYSDEC REGIONAL JURISDICTIONS

As a general rule, much of the environmental regulation encountered by any project will be administered by the New York State Department of Environmental Conservation (NYSDEC). New York State is divided into nine different NYSDEC regions, as shown in Figure 1. It is advisable, early in the development process, to consult the regional NYSDEC office that would have jurisdiction over the project. If consulted early in the development process, NYSDEC regulators may be able to provide valuable information to the developer based on their experience and knowledge of similar projects. Regional NYSDEC officers may be identified and contacted through the NYSDEC Website, at http://www.dec.ny.gov/.

Figure 1. NYSDEC Regional Map. Source: New York State Department of Environmental Conservation.

Region 1: Nassau and Suffolk Counties
Region 2: Brooklyn, Bronx, Manhattan, Queens and Staten Island
Region 3: Dutchess, Orange, Putnam, Rockland, Sullivan, Ulster and Westchester Counties
Region 4: Albany, Columbia, Delaware, Greene, Montgomery, Otsego, Rensselaer, Schenectady and Schoharie Counties
Region 5: Clinton, Essex, Franklin, Fulton, Hamilton, Saratoga, Warren and Washington Counties
Region 6: Herkimer, Jefferson, Lewis, Oneida and St. Lawrence Counties
Region 7: Broome, Cayuga, Chenango, Cortland, Madison, Onondaga, Oswego, Tioga and Tompkins Counties
Region 8: Chemung, Genesee, Livingston, Monroe, Ontario, Orleans, Schuyler, Seneca, Steuben, Wayne and Yates Counties
Region 9: Allegany, Chautauqua, Cattaraugus, Erie, Niagara and Wyoming Counties

1.4 ENVIRONMENTAL PERMITTING

1.4.1 Introduction to Environmental Permitting

Each biomass project developer will need to holistically address both environmental and local building requirements, the latter often driven by municipal zoning as it applies to the development site. The environmental and local building permitting paths must be handled together and will dovetail. Acquiring municipal permits to build on a selected site is not in itself an environmental process, but could have related requirements.

Frequently, some operational requirements of the proposed project will fall outside of the activities allowed by the local zoning ordinance for the intended project site. In this case, a special use permit or zoning variance may be required.[2] Generally, zoning variances are not easy to achieve, and efforts should be made, through thoughtful site planning and site selection, to avoid the need for a variance.

Early in the development process, it is advisable to address any potential environmental impacts of the project. This will involve the following steps:

- Identify all distinct environmental features of the intended project site, including features of both the natural and built environments
- Identify potential impacts to these features from both site development and from the projected normal operations of the project
- Identify mitigation strategies to address these potential impacts
- Identify and enlist the assistance of all regulatory agencies with jurisdiction over the project

The developer should also assess the value of bringing environmental and planning professionals on board early in the permitting process. Planners advise towns on zoning and comprehensive plans, and help town boards and agencies deal with development proposals. A local planner will be familiar with local issues and concerns. Hiring a planner with experience in the town to represent the developer before town boards, review blueprints, etc. can save time and trouble for the developer.

As previously stated, it is also advisable to inform the public of the proposed project as early as possible. Note, however, that going "public" with a proposed project requires careful timing. The developer needs to be far enough into the development process to be able to address public questions and give specific answers, but not so far along that there is a risk of significant stranded investment if aspects of the project plan must be changed.

1.4.2 Sources of Environmental Exposure

The environmental permitting requirements for any biomass facility will result from three possible types of environmental exposure (see Figure 2):

1. Exposure due to site characteristics
2. Exposure due to process emissions and material handling/disposal
3. Exposure due to internal operational processes

Each of these types of environmental exposure is discussed in the following sections.

[2] An alternative to seeking a special use permit or zoning variance is to ask the local authorities to change the zoning ordinance to accommodate the proposed project. For example, if biomass-to-energy facilities are not listed among the permitted uses in an industrial zone where other electricity-generating facilities are permitted, the town may add biomass facilities to the list of permitted facilities in that zone. Note that any proposed changes to zoning must reflect a comprehensive land-use plan and benefit the entire community. Zoning changes to benefit one specific location or facility are called "spot zoning," and are not legal in New York State.

Figure 2. Potential Environmental Exposures of a Biomass Facility.

Table 1 summarizes the most significant permitting requirements for a biomass project within New York State. It is important to note that project impacts and local ordinances will vary significantly from one locale to another. Therefore, not all the permitting requirements covered here will apply to each project; conversely, additional requirements not covered in this guidebook may be applicable to some projects.

Table 1. New York State Environmental Siting/Permitting Requirements for Biomass Projects. Source: New York State Department of Environmental Conservation.

Agency	*Approval*	*Trigger*	*Description*
State			
Lead Agency varies by project	**SEQR Requirements; Part 617**	**Review thresholds established by state statute**	**New York State has its own environmental review process embodied in its Part 617 regulations. If Federal and State reviews are both required, one environmental impact assessment is typically coordinated among the agencies involved.**
NYSDEC; USACE	**Wildlife and habitat consultation/permit under Part of 6NYCRR Part 617**	**Impacts to state wildlife (plants/animals)**	**NYSDEC is the caretaker of New York State's lands and habitat thus protecting and managing wild plants and animals.**
New York State Historic Preservation Office (SHPO)	**Cultural, historic, and archaeological resources consultation/studies/permits - 6NYCRR Part 617**	**Potential impacts to cultural resources**	**New York State has preservation regulations programs similar to the federal historic preservation program. Consultation with the SHPO and State Archaeologist identifies potential impacts and any studies and permits that would be required.**
NYSDEC; USACE	**State Permits from (Article 24), USACE (Section 408)**	**Work in/impact to State or Federal designated wetlands**	**Impacts to onsite or adjacent designated State or Federal Wetlands must first be approved via permit by NYSDEC and the USACE.**
NYSDEC	**SPDES Permit; Permit for stormwater discharges**	**Potential for discharge from site construction and operations**	**New York State administers this program under NYSDEC - SPDES Permit Regulations**

NYSDEC	**Solid Waste Permit under Part 360**	**Need for operation of a Solid Waste Facility**	**Certain biomass facilities by nature of their operation may require a Solid Waste Permit (see description later in this subsection)**
NYSDEC	**Under Part 200/201 of State Regulations**	**Need for Air Need for Air Emissions Permit**	**Air emission permits are Air emission permits are issued in New York State by NYSDEC. Emissions are considered as either "minor" or "major." NYSDEC administers the air program in New York under delegation agreement from the Federal government.**
NYSDEC; Local Agency	**Under Division of Water Parts 700-750; Local Sewer ordinance**	**Need for SPDES Wastewater Discharge Permit**	**Discharges to surface waters and groundwaters of New York State are permitted by NYSDEC per New York Environmental Laws. Discharges to sanitary sewer systems are permitted pursuant to local sewer ordinances.**

1.4.2.1 Site Characteristics

In general, there are two types of sites that may be chosen for project development: existing sites, where an existing facility may require retrofitting and/or expansion; and new ("greenfield") sites, which are being developed for the first time. Brownfield or abandoned industrial sites can be considered a subset of the new sites category. However, the developer considering brownfield development should be mindful that while there may be savings due to the presence of existing infrastructure, or as a result of brownfield development incentives, the site may be encumbered with latent environmental liabilities due to previous activities.

In general, any potential development site may be seen as a bundle of unique features. It is important to understand which of these features may make development more difficult, expensive, or time-consuming. A partial listing of some of these features would include:

- Incompatible present land usage
- Inappropriate zoning classification
- Undesirable soil type(s)
- Undesirable topography
- Site contains or is contiguous to a building, site or district listed on a State or National Registry of Historic Places
- Site is contiguous to a site listed on the Register of National Natural Landmarks
- Shallow depth to bedrock
- Site is presently used as public open space or for recreation
- Site is not served by public utilities
- Site is located within an agricultural district certified pursuant to Agriculture and Markets Law
- Site is not appropriate to size of project
- Site is not appropriate to duration of project construction
- Site cannot handle traffic generated by project (both construction and operations related)
- Site preparation requires blasting
- Site preparation requires materials removal/disposal
- Site preparation requires approvals/permits (local, state, federal)
- Site development requires zoning changes/variances
- Incompatible surrounding zoning and land uses
- Existence of federal or state wetlands on site or nearby
- Existence of floodplains
- Existence of lakes, streams and/or ponds on site
- Significant vegetation on site to be removed
- Nearby residential or public use areas where noise, odors, traffic and other aspects of facility operations may be objectionable
- Site is located within or substantially contiguous to a Critical Environmental Area as defined under SEQRA (an example would be classified wetlands where sensitive plants and/or animals may exist).[3]
- Site contains threatened/endangered species (plants, animals)
- Too-deep or too-shallow depth to groundwater
- Presence of a drinking water aquifer
- Site has scenic views, or is contiguous to scenic views
- Site development may cause visual/aesthetic impacts(s)
- Mature forests to be removed

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[3] According to the New York State online Citizens' Guide, "A Critical Environmental Area (CEA) is land that has earned special protection under SEQR regulations. To be designated a CEA, the area must have one or more of the following characteristics: It is a benefit or threat to human health. It is a natural setting. Wildlife habitats, wetlands, forests, and lakes are some examples of a natural setting. It has agricultural, social, cultural, historic, archaeological, recreational, or educational values. It has an inherent ecological, geological or hydrological sensitivity to change that may be adversely affected by any change." (New York State online Citizens' Guide)

- Site has past history of contamination
- Site has cultural/archaeological significance
- Presence of unique/unusual land forms

Existing Sites

In some cases, biomass projects will constitute retrofits or expansions of existing facilities; in these cases, much will be determined by the existing facility configuration.

Existing sites are likely to need attention particularly with regard to physical site constraints that could impede development. The developer also should be alert to the possible presence of past environmental encumbrances. The development plan will also need to be assessed against any physical elements that may require municipal approvals or variances, and/or planned activities that require new permits or permit modifications. Note that permits may not be transferable from an existing owner to a new owner.

With respect to past environmental site encumbrances, see discussion later in this section about the merits of having a Phase I Environmental Site Assessment (ESA) performed for sites/operations that are to be purchased. This assessment can help to identify latent environmental exposure that may come with the property. Once purchased, pre-existing environmental liabilities become the responsibility of the new owner unless legal pre-purchase paperwork states otherwise.

New Sites

In many cases the site will be new. New sites are usually selected based on a number of factors not related to environmental concerns, such as parcel size and location, price, and proximity to infrastructure. These are important considerations. However, environmental and community concerns are also very important, and should not be an afterthought in site selection. Many proposed projects have failed due to environmental issues and negative public opinion.

Prudent site selection, enabled by a thorough understanding of the area's environmental conditions, can help expedite approval of a biomass project. By contrast, selecting a site that includes environmentally sensitive features can cost the developer both time and money. For example, if a site contains listed federal or state wetlands that have not been recently mapped, they will require surveying so their boundaries and buffer zones can be re-established. The quality of the wetlands will have to be classified, and they will have to be shown on all relevant development drawings. Development on the site will require NYSDEC and US Army Corps approval. If the developer proposes encumbering and/or removing wetlands, replacement wetlands may be required at an acreage exchange rate significantly greater than one-to-one. This requirement is a frequent cause of delays, as acceptable replacement wetlands can become the subject of debate between the developer and the governing agencies.

Before any site is purchased for development of a biomass project a Phase I Environmental Site Assessment (ESA) should be conducted. This is sometimes referred to as an environmental screening analysis, preliminary risk assessment and/or preliminary site assessment. During a Phase I ESA, which should be compliant with ASTM E 1528,[4] potential environmental site liabilities should be uncovered. The Phase I ESA is typically a desktop review performed by environmental professionals with expertise in various disciplines; using publicly available resources, they will identify problems based on past uses of the site(s) under consideration.

[4] ASTM E 1528 - Practice for Limited Environmental Due Diligence: Transaction Screen Process, is under the jurisdiction of ASTM International Committee E50 on Environmental Assessment, Risk Management and Corrective Action, Subcommittee E50.02 on Real Estate Assessment and Management. Practice E 1528 is a tool for identifying any current or past potential environmental concerns at low risk sites (those for which Comprehensive Environmental Response, Compensation and Liability Act [CERCLA] liability immunity is not a concern). ASTM International is an international standards organization.

Results of a Phase I ESA may indicate that a potential site is not feasible or would be too costly to pursue from an environmental perspective. Alternatively, results may show that the site is worth continued pursuit and that any identified environmental concerns appear manageable. If some issues prove significant during the Phase I effort, and the decision is to continue pursuit of the site, then a Phase II ESA should be conducted to help quantify the extent of environmental exposure the site may present to the potential buyer.

In tandem with this effort, a preliminary review of the Long Form Environmental Assessment Form (EAF), which can be found online at www.dec.ny.gov/docs/permits_ej_operations_pdf/longeaf.pdf, will help identify other potential development issues. The Long Form EAF is part of the environmental assessment process mandated by the State Environmental Quality Review Act (SEQRA), which will be applicable to any biomass project developed in New York State (with the possible exception of some minor retrofitting of existing facilities). The SEQRA mandated environmental assessment process is discussed in greater detail below. Summary information on environmental permitting issues is presented in Table 2.

The ability to mitigate those impacts that can't be avoided will be very important in securing project approvals. However, there may be some issues that would require mitigation at such significant cost as to threaten the project's financial feasibility. This underlines the importance of proper site selection, which can help avoid many, if not all, potential environmental impacts, and of early evaluation of potential environmental impacts and the likely cost of mitigation.

1.4.2.2 Process Emissions and Material Handling/Disposal.

Emissions and materials-related permitting requirements are generally a function of processes that generate emissions to the air, water and land. These emissions fall into the following regulatory categories:

- Stormwater - General/Industrial
- Solid Waste
- Air
- Wastewater

Each regulatory category is discussed below. Additionally, Table 2 summarizes some of the more salient issues that the potential developer of a biomass facility should consider.

Table 2. SEQR Summary – New York State Siting. Source: New York State Department of Environmental Conservation.

Environmental Review Issue	*Issues to Address*	*Regulatory Framework*	*Agencies*	*Comments (e.g. preliminary applicability, approvals, programs)*
Agricultural Land Resources	Protection of farmlands Acquisition of farm lands	1NYCRR 370 Article 25-AA of NYS Agriculture & Markets Law, Sections 303, 304 & 305	NYS Department of Agriculture & Markets - Cornell University maintains maps	NOI and Public Review for acquisition of more than one acre active farm or more than 10 acres in an Agriculture District
Aesthetic Resources	Visual appearance Buffering Adjacent Zoning/Activities	Local Zoning Code	Local municipality NYSDEC	Public Hearings/Comment Period relative to visual impacts Prelim/Final Flat Approval
Historic and Archaeological Resources	Historical Places	Federal Historical Places State Historical Places Local Historical Places National Natural Landmarks	SHPO NYS Parks and Recreation NYSDEC	Site archaeological survey likely required Evaluations as required by SEQR
Open Space and Recreation	Impact to adjacent property uses Taking public lands Abutting property uses	Local Zoning Code Local Development Master Plan	Local municipality County, State, Local, Federal Parks	Public Hearings /comments Period Prelim/Final Flat Approval
Critical Environmental Areas	Wetlands Flood plains Endangered/threatened species	Article 24 State Wetlands Federal Wetlands Federal Flood Maps Laws protecting species	NYSDEC USACE FEMA ECL Articles 6NYCRR 617	Professional Assessments Field Classifications Boundary determinations required
Transportation	Highway access Utilities access to site Work in ROW	NYS Transportation Code State DOT Standards County/Local Regulations	NYSDOT County Highway Department Local Highway Department	Traffic study may be required Evaluate impacts to area
Energy	Capacity of needed utilities Impacts to existing infrastructure Buildings built to State code	NYS Building Code NYS Energy Code Local Approvals	NYSERDA State Code Local Building Inspector Local Agencies	Permit and connection permissions required Building Permit & Certificate of Occupancy required
Noise and Odor	Noise above ambient/background Offensive odors	Local Zoning Codes State Impacts	Local municipality NYSDEC	Must support no impacts and/or mitigations necessary to address emitted noise/odor

Public Health	**Handling of liquid/solid/hazardous wastes produced by project** **Health & Safety onsite**	**Federal Regulations** **State Regulations** **County Health Code** **Fire Codes**	**State Health Department** **County Health Department** **State Solid Waste Master Plan** **NYSDEC** **OSHA** **Local Fire Department**	**Prepare proper H&S documents and procedures** **Notify affected agencies** **Obtain Permits**
Growth and Character of Community or Neighborhood	**Local impacts to project** **Necessary mitigation**	**Local Zoning Code** **Development Master Plan** **Restricted corridors**	**Local Municipality**	**Incorporated project Features such as landscaping and hours of operation, to minimize impacts**

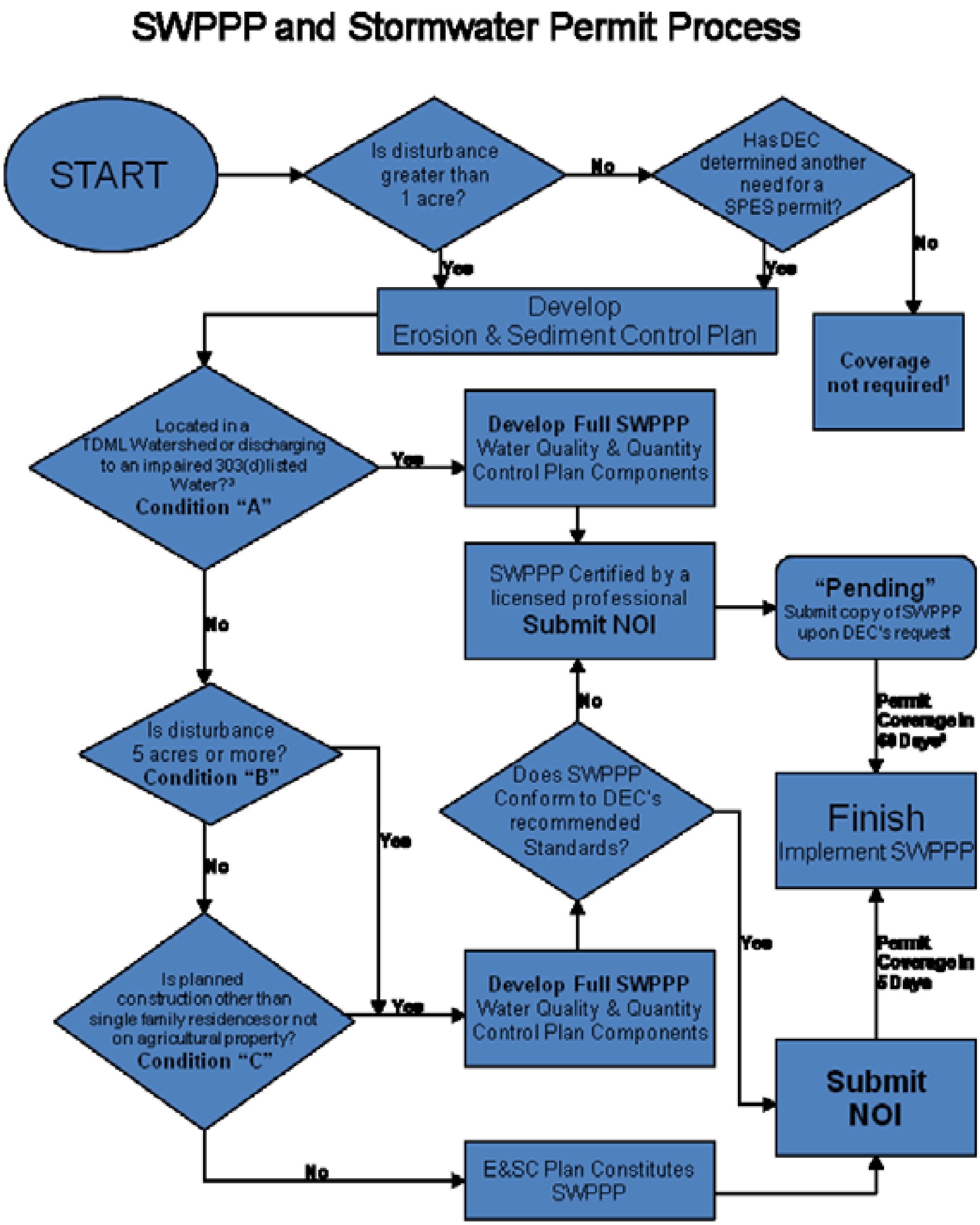
Stormwater Regulations

The size and configuration of the site and its surroundings, and the nature of operational activities on and near the site, will determine stormwater regulatory needs. In addition, stormwater runoff during project construction may require attention.

Stormwater requirements within New York State are regulated by NYSDEC under a delegation agreement with the United States Environmental Protection Agency (USEPA) and follow the requirements, where New York State implements, of Section 402 of the federal Clean Water Act (CWA).[5] If a proposed biomass project will disturb more than one acre, and is not located on agricultural land, then the site may require a permit to discharge stormwater. The required permit would be one of two types of State Pollution Discharge Elimination System (SPDES) permit: A Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity (GP-0-06-002), or an individual industrial SPDES permit. Under certain circumstances and with sufficient documentation it is possible that a “No Exposure Exclusion” could be issued if industrial activities are not exposed to stormwater. Additionally a stormwater pollution prevention plan (SWPPP) and stormwater infrastructure may be required unless the “No Exposure Exclusion” is satisfied. A flow chart depicting the normal permitting process is shown in Figure 3.

[5] A delegation agreement delegates administrative authority over a program. In this case, the USEPA delegated administration of section 402 of the federal CWA in New York State to the NYSDEC.

Figure 3. SWPPP and Stormwater Permit Process. Source: New York Department of Environmental Conservation, Chapter 3, Section 3.1, Filing for a Stormwater Permit.



NOTES:

1. Under any of the above conditions other environmental permits may be required. DEC may require permit for construction disturbance < 1 acre on a case by case basis.
2. and the following exists: construction and/or stormwater discharges from the construction or post-construction site contain the pollutant of concern identified in the TMDL or 303(d) listing.
3. After receipt by DEC of completed application.

Table 3 categorizes industrial activities by sector. A review of this table indicates that the types of biomass projects addressed by this guidebook are not specifically covered by these regulations. Thus, unless NYSDEC elects for a given project to require permit coverage under Sectors AD & AE "Non-Classified Facilities/Stormwater Discharges Designated by the Department As Requiring Permits," a stormwater permit may not be required. Anaerobic digester projects located at an agricultural site would likely not be required to obtain a stormwater permit but would require an erosion/stormwater plan during construction.

Table 3. Sectors of Industrial Activity Covered Under the SPDES Multi-Sector General Permit. Source: New York State Department of Environmental Conservation.

SIC Code or Activity Code	Activity Represented
Sector A: Timber Products	
2411………………………………………	Log Storage and Handling (Wet deck storage areas are only authorized if no chemical additives are used in the spray water or applied to the logs).
2421………………………………………	General Sawmills and Planning Mills.
2426………………………………………	Hardwood Dimension and Flooring Mills.
2429………………………………………	Special Product Sawmills, Not Elsewhere Classified
2431-2439 (except 2434 – see Sector W)...	Millwork, Veneer, Plywood, and Structural Wood.
2441, 2448, 2449…………………………	Wood Containers.
2451, 2452………………………………..	Wood Buildings and Mobile Homes.
2491………………………………………	Wood Preserving.
2493………………………………………	Reconstituted Wood Products.
2499………………………………………	Wood Products, Not Elsewhere Classified.
Sector B: Paper and Allied Products	
2611………………………………………	Pulp Mills.
2621………………………………………	Paper Mills.
2631………………………………………	Paperboard Mills.
2652-2657………………………………..	Paperboard Containers and Boxes.
2671-2679………………………………..	Converted Paper and Paperboard Products, Except Containers and Boxes.
Sector C: Chemical and Allied Products	
2812-2819………………………………..	Industrial Inorganic Chemicals.
2821-2824………………………………..	Plastics Materials and Synthetic Resins, Synthetic Rubber, Cellulosic and Other Manmade Fibers Except Glass.
2833-2836………………………………..	Medicinal Chemicals and Botanical Products; Pharmaceutical Preparations; In Vitro and In Vivo Diagnostic Substances; Biological Products, Except Diagnostic Substances.
2841-2844………………………………..	Soaps, Detergents, and Cleaning Preparations; Perfumes, Cosmetics, and Other Toilet Preparations.
2851………………………………………	Paints, Varnishes, Lacquers, Enamels, and Allied Products.
2861-2869………………………………..	Industrial Organic Chemicals.
2873-2879………………………………..	Agricultural Chemicals.
2891-2899………………………………..	Miscellaneous Chemical Products.
3952 (limited to list) ……………………..	Inks and Paints, Including China Painting Enamels, India Ink, Drawing Ink, Platinum Paints for Burnt Wood or Leather Work, Paints for China Painting, Artists' Paints and Artists' Watercolors.
Sector D: Ashpalt Paving and Roofing Materials and Lubricants	
2951, 2952………………………………..	Asphalt Paving and Roofing Materials.
2992, 2999………………………………..	Miscellaneous Products of Petroleum and Coal.

Sector E: Glass, Clay, Cement, Concrete, and Gypsum Products	
3211………………………………………	Flat Glass.
3221, 3229………………………………..	Glass and Glassware, Pressed or Blown.
3231………………………………………	Glass Products Made of Purchased Glass.
3241………………………………………	Hydraulic Cement.
3251-3259………………………………..	Structural Clay Products.
3261-3269………………………………..	Pottery and Related Products.
3271-3275………………………………..	Concrete, Gypsum and Plaster Products.
3281………………………………………	Cut Stone and Stone Products.
3291-3299………………………………..	Abrasive, Asbestos, and Miscellaneous Non-metallic Mineral Products.
Sector F: Primary Metals	
3312-3317………………………………..	Steel Works, Blast Furnaces, and Rolling and Finishing Mills.
3321-3325………………………………..	Iron and Steel Foundries.
3331-3339………………………………..	Primary Smelting and Refining of Nonferrous Metals.
3341………………………………………	Secondary Smelting and Refining of Nonferrous Metals.
3351-3357………………………………..	Rolling, Drawing, and Extruding of Nonferrous Metals.
3363-3369………………………………..	Nonferrous Foundries (Castings).
3398, 3399………………………………..	Miscellaneous Primary Metal Products.
Sector G: Metal Mining (Ore Mining and Dressing)	
1011………………………………………	Iron Ores.
1021………………………………………	Copper Ores.
1031………………………………………	Lead and Zinc Ores.
1041, 1044………………………………..	Gold and Silver Ores.
1061………………………………………	Ferroalloy Ores, Except Vanadium.
1081………………………………………	Metal Mining Services.
1094, 1099………………………………..	Miscellaneous Metal Ores.
Sector I: Reserved	
Sector I: Oil and Gas Extraction and Refining	
1311………………………………………	Crude Petroleum and Natural Gas.
1321………………………………………	Natural Gas Liquids.
1381-1389………………………………..	Oil and Gas Field Services.
2911………………………………………	Petroleum Refineries.
Sector J: Mineral Mining and Dressing	
1411………………………………………	Dimension Stone.
1422-1429………………………………..	Crushed and Broken Stone, Including Rip Rap.
1442, 1446………………………………..	Sand and Gravel.
1455, 1459………………………………..	Clay, Ceramic, and Refractory Materials.
1474-1479………………………………..	Chemical and Fertilizer Mineral Mining.
1481………………………………………	Nonmetallic Minerals Services, Except Fuels.
1499………………………………………	Miscellaneous Nonmetallic Minerals, Except Fuels.
Sector K: Hazardous Waste Treatment, Storage, or Disposal Facilities	
HZ………………………………………..	Hazardous Waste Treatment, Storage or Disposal.
Sector L: Landfills and Land Application Sites	
LF………………………………………..	Landfills, Land Application Sites, and Non-Compliant Landfills.
Sector M: Automobile Salvage Yards	
5015………………………………………	Automobile Salvage Yards.
Sector N: Scrap Recycling Facilities	
5093………………………………………	Scrap Recycling Facilities.
4499 (limited to list)……………………...	Dismantling Ships, Marine Salvaging, and Marine Wrecking – Ships For Scrap.

Sector O: Steam Electric Generating Facilities	
SE………………………………………..	Steam Electric Generating Facilities.
Sector P: Land Transportation and Warehousing	
4011, 4013………………………………..	Railroad Transportation.
4111-4173………………………………..	Local and Highway Passenger Transportation.
4212-4231………………………………..	Motor Freight Transportation and Warehousing.
4311………………………………………	United States Postal Service.
5171………………………………………	Petroleum Bulk Stations and Terminals.
Sector Q: Water Transportation	
4412-4499 (except 4499 facilities as specified in Sector N)………………………………….	Water Transportation.
Sector R: Ship and Boat Building or Repairing Yards	
3731, 3732………………………………..	Ship and Boat Building or Repairing Yards.
Sector S: Air Transportation	
4512-4581………………………………..	Air Transportation Facilities.
Sector T: Treatment Works	
TW………………………………………	Treatment Works.
Sector U: Food and Kindred Products	
2011-2015………………………………..	Meat Products.
2021-2026………………………………..	Dairy Products.
2032-2038………………………………..	Canned, Frozen and Preserved Fruits, Vegetables and Food Specialties.
2041-2048………………………………..	Grain Mill Products.
2051-2053………………………………..	Bakery Products.
2061-2068………………………………..	Sugar and Confectionary Products.
2074-2079………………………………..	Fats and Oils.
2082-2087………………………………..	Beverages.
2091-2099………………………………..	Miscellaneous Food Preparations and Kindred Products.
2111-2141………………………………..	Tobacco Products.
Sector V: Textile Mills, Apparel, and Other Fabric Product Manufacturing, Leather and Leather Products	
2211-2299………………………………..	Textile Mills Products.
2311-2399………………………………..	Apparel and Other Finished Products Made From Fabrics and Similar Materials.
3131-3199 (except 3111 – see Sector Z)…	Leather and Leather Products, except Leather Tanning and Finishing.
Sector W: Furniture and Fixtures	
2434………………………………………	Wood Kitchen Cabinets.
2511-2599………………………………..	Furniture and Fixtures.
Sector X: Printing and Publishing	
2711-2796………………………………..	Printing, Publishing and Allied Industries.
Sector Y: Rubber, Miscellaneous Plastic Products, and Miscellaneous Manufacturing Industries	
3011………………………………………	Tires and Inner Tubes.
3021………………………………………	Rubber and Plastics Footwear.
3052, 3053………………………………..	Gaskets, Packing, and Sealing Devices and Rubber and Plastics Hose and Belting.
3061, 3069………………………………..	Fabricated Rubber products, Not Elsewhere Classified.
3081, 3089………………………………..	Miscellaneous Plastics Products.
3931………………………………………	Musical Instruments.
3942-3949………………………………..	Dolls, Toys, Games and Sporting and Athletic Goods.
3951-3955 (except 3952 facilities as specified in Sector C) ………………………………...	Pens, Pencils, and Other Artists' Materials.
3961-3965………………………………..	Costume Jewelry, Costume Novelties, Buttons, and

3991-3999………………………………..	Miscellaneous Notions, Except Precious Metals. Miscellaneous Manufacturing Industries.
Sector Z: Leather Tanning and Finishing	
3111………………………………………	Leather Tanning, Currying and Finishing.
Sector AA: Fabricated Metal Products	
3411-3499………………………………..	Fabricated Metal Products, Except Machinery and Transportation Equipment.
3911-3915………………………………..	Jewelry, Silverware, and Plated Ware.
Sector AB: Transportation Equipment, Industrial or Commercial Machinery	
3511-3599 (except 3571-3579 – see Sector AC)	Industrial and Commercial Machinery (Except Computer and Office Equipment).
3711-3799 (except 3731, 3732 – see Sector R)	Transportation Equipment (Except Ship and Boat Building and Repairing).
Sector AC: Electronic, Electrical, Photographic and Optical Goods	
3571-3579………………………………..	Computer and Office Equipment.
3612-3699………………………………..	Electronic, Electrical Equipment and Components, Except Computer Equipment.
3812-3873………………………………..	Measuring, Analyzing and Controlling Instrument; Photographic and Optical Goods.
Sector AD & AE: Non-Classified Facilities/Stormwater Discharges Designated By the Department As Requiring Permits	
NA……………………………………….	Other Stormwater Discharges Designated By the Department As Needing a Permit or Any Facility Discharging Stormwater Associated With Industrial Activity Not Described By Any of Sectors A-AC. Note: Facilities may not elect to be covered under Sector AD & AE. Only the Department may assign a facility to Sector AD & AE.

There are also particular NYSDEC requirements that may impact projects located on Long Island. Since the Long Island geology is basically sand, projects proposed for either Nassau or Suffolk Counties may be subject to additional requirements. Regulators in NYSDEC Region 1 should be consulted.

Specific additional permit requirements may also be required if the proposed project is to be located within the greater New York City metropolitan area or its watersheds. In these cases, the New York City Department of Environmental Protection (NYCDEP) environmental code should also be consulted for any additional or related stormwater permits/approvals.

Solid Waste Regulations

Biomass projects may be subject to solid waste regulations either because they use regulated feedstocks, e.g., residual materials from construction or demolition activities, or because they generate combustion residuals, such as ash containing metals, the handling and disposal of which are subject to these regulations.

The initial determination of whether a prospective biomass project may fall under the jurisdiction of NYSDEC Solid Waste Management Program Part 360 rests with the definition of “solid waste.” The terms “Anaerobic digestion,” “gasification,” “co-fire” and “biomass” do not have specific definitions within the solid waste management regulations spelled out in 6NYCRR Part 360 - Solid Waste Management Facilities. However, the definition in part reads, “any garbage, refuse, sludge from a wastewater treatment plant, water supply treatment plant, or air pollution control facility and other discarded materials including solid, liquid, semi-solid, or contained gaseous material, resulting from industrial, commercial, mining and agricultural operations.” A material would be considered as “discarded” if it is “disposed, burned/incinerated, including burned as fuel for the purpose of recovering usable heat, or accumulated, stored or physically, chemically or biologically treated instead of or before being disposed of." Therefore, although not specifically addressed in the regulations, a biomass facility may still require a permit based on general definitions found in Part 360. Since there is not a specific category for this type of facility within Part 360, if a solid waste permit is required it will likely be a combination of the General Requirements under 360-1, and specific requirements that are triggered by the features of the proposed project, such as the project type, its size, the materials it accepts and its location.

Projects located at an agricultural site that accepts site-generated organic materials may be exempt from Part 360 regulation. However, similar projects that accept certain materials (e.g., fats, oils, and grease) generated off-site may require a Part 360 permit. Material that is grown on site as a fuel source but is not being discarded is not leaving the site and is being used as a fuel may not require a Part 360 permit.

Early in the development process, project developers should consult with NYSDEC regulators having jurisdiction over the region where the project is proposed. Such consultations offer the best opportunity to eliminate any ambiguity about solid waste permit requirements.

If the project is to be sited within the greater New York City metropolitan area or its watersheds, New York City Department of Environmental Protection (NYCDEP) regulations may pose additional solid waste permitting requirements. In this case, NYCDEP regulators should also be contacted early in project development, to assess the need for any additional permitting.

Local Solid Waste Management Plans (SWMP)

Biomass projects, because of combustion waste they may produce and "waste" materials they may use for fuel, may have an impact on an existing local solid waste management plan.

Counties are required to develop a SWMP under New York State Environmental Conservation Law Section 27-0103. The requirements of the law are administered by NYSDEC. Biomass projects may impact the host county's SWMP, requiring the affected county to reevaluate its SWMP; in some cases, the state may even require the county to update the plan. This could delay the project's development schedule, necessary permits, local approvals and overall progress. Once a project is sufficiently scoped by the developer, it is best to discuss this issue with NYSDEC in order to determine possible impacts on the local SWMP.

It should be noted that NYSDEC is undertaking, in 2009, the task of developing a new statewide SWMP, incorporating a comprehensive re-evaluation of the state's solid waste policies, programs, plans and goals.

Air Regulations

Air emissions from the combustion of biomass based fuels, and from the handling and processing of biomass feedstocks, are a primary focus of air quality regulation under federal and State law.

NYSDEC administers the air permitting program within New York State under delegation agreement from the federal government. Permitting generally follows the requirements of the Federal Clean Air Act (CAA) and is administered under New York State law, most notably 6 NYCRR Part 201.

Air permit applications are categorized into two primary groups, each with two sub-categories:

- Major emissions sources
    - State Facility Permit required
    - Title V Facility Permit required

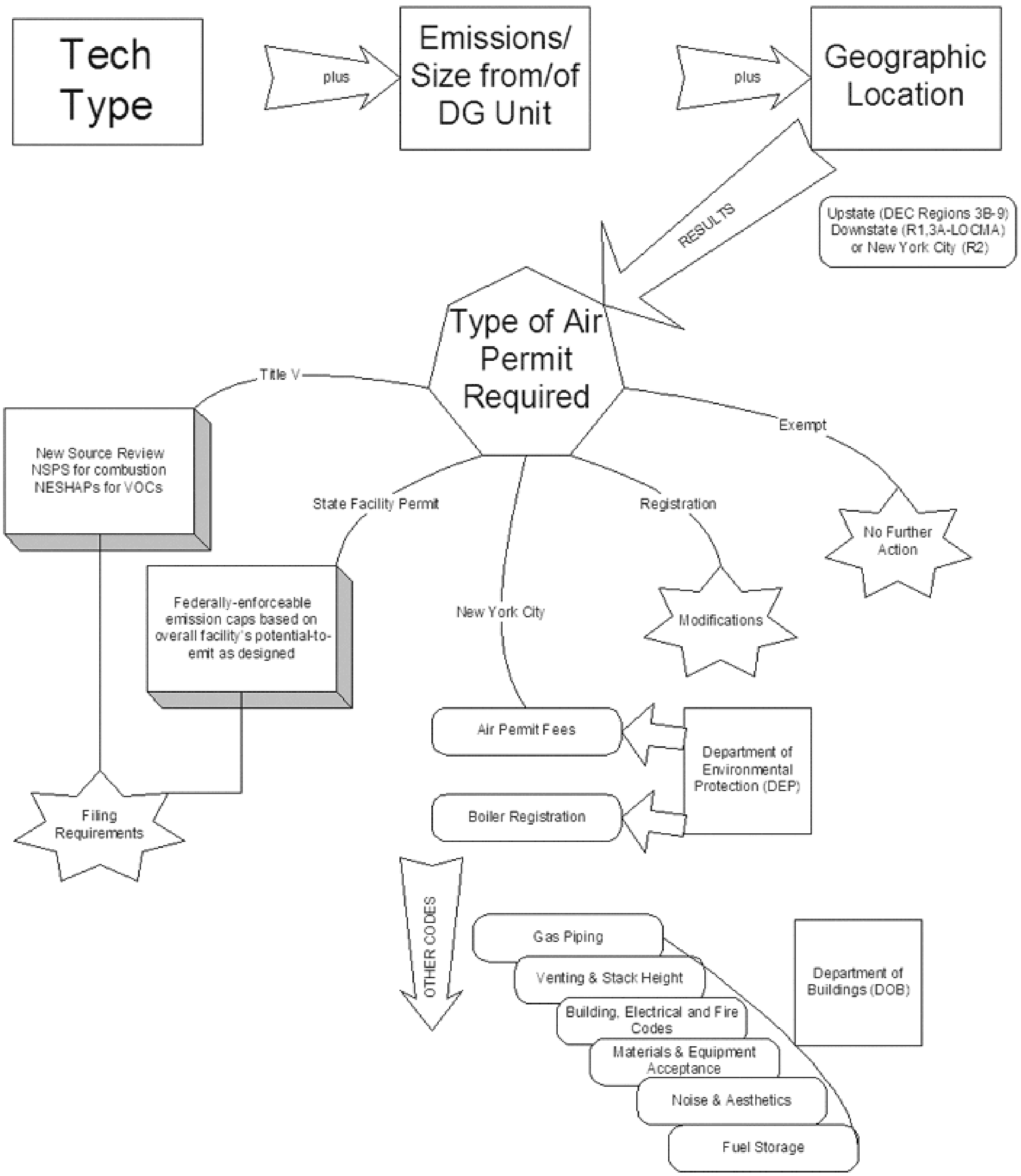
- Minor emissions sources
    - Exempt
    - Minor (requiring only registration)

Major sources are defined as any stationary source or group of stationary sources that emits or has the potential to emit (PTE) at least 10 tons/year of any hazardous air pollutant (HAP) or 25 tons/year of any combination of HAPs.[6]

Figure 4 shows in graphic form the air permitting sequence within New York State. Exemptions and trivial activities are covered in Subpart 201-3. Minor facility registration criteria can be found in Subpart 201-4. State facility permits are issued to facilities that are not considered “major” as defined in the regulations, but meet the criteria of Subpart 201-5. Title V facility permits are issued to facilities subject to Subpart 201-6 and include facilities judged to be “major” by department definition or which are subject to the New Source Performance Standards (NSPS) or other requirements regulating hazardous air pollutants or federal acid rain program requirements.

[6] For more information on major and minor emissions sources, refer to the federal Clean Air Act, section 112(a)(1).

Figure 4. New York State Distributed Generation Siting, Permitting and Codes Process Flow. Source: NYSERDA.



Note that in early 2009 NYSDEC adopted amendments to Part 200-General Provisions, Part 201-Permits and Registrations, and Part 231 New Source Review for New and Modified Facilities. Essentially these rule revisions address the permitting, emissions control and record keeping requirements for new major facilities, major modifications at existing major facilities, and major modifications to existing non-major facilities that are located in New York State. With the continued push for alternative energy sources throughout the US and New York State, more new rules and amendments are likely; the biomass project developer must keep abreast of such changes to the regulatory landscape.[7]

Table 4 shows that a facility can be considered a major stationary source under Part 201 if it exceeds the quantity for contaminants in the state affected areas indicated. As discussed above, non-major facilities that meet the criteria of Subpart 201-4 can register under the department's permitting program and do not need a permit. Thus, such registrations are ministerial in nature and have no formal notice requirements.

Table 4. Title V – Major Stationary Sources.

Classification of Area by Contaminant	Affected Area, by County	Contaminant & Quantity (in tons per year)
Attainment Area for Regulated Air Pollutants[1]	Areas not specifically listed in any of the areas classified as Non-attainment.	CO....100 PM-10....100 NOx....100 VOC....100
Moderate Non-attainment Area for CO	Bronx, Kings, Nassau, New York[2], Queens, Richmond[3], Westchester	CO....100
Moderate Non-attainment Area for PM-10	New York	PM-10....100
Ozone Transport Region/ Moderate Non-attainment Area for NOx & VOC	All of New York State except areas listed as Severe Non-attainment Area for NOx & VOC	NOx ....100 VOC 50
Severe Non-attainment Area for NOx & VOC	Bronx, Kings, Lower Orange County Metropolitan Area[4], Nassau, New York, Queens, Richmond, Rockland, Suffolk, Westchester	NOx ....25 VOC 25

Notes:
[1] Carbon Monoxide (CO), Particulate Matter (PM-10), Oxides of Nitrogen (NOx), & Volatile Organic Compounds (VOC)
[2] New York County = New York City borough of Manhattan
[3] Richmond County = New York City borough of Staten Island
[4] Towns of Blooming Grove, Chester, Highlands, Monroe, Tuxedo, Warwick and Woodbury

[7] One specific change being contemplated at the federal level has to do with the way air emissions from boilers are regulated. During 2004, EPA promulgated 40 CFR Part 63, Subpart DDDDD, which established national emission limits and work practice standards for major sources of HAPs emitted from industrial, commercial, and institutional solid fuel boilers and process heaters larger than 10 mBtu. EPA has been under a court-ordered schedule to promulgate area source emission standards for all commercial and institutional boilers under the Clean Air Act (CAA). EPA is required to propose area source boiler standards by July 15, 2009 and promulgate by July, 2010. EPA is proposing to eliminate the size threshold for boilers from the regulations, meaning all new industrial and commercial boilers would be required to meet or control emission levels to a new standard.

In interpreting and applying air quality regulations, the size, type and location of the individual project will be very important.

Anaerobic digesters are not themselves considered to be sources of air pollution, although if the digester gas is being used to generate electricity and heat on-site, the combustion unit (usually a CHP unit) would most likely be subject to regulation as a new combustion source. CHP units associated with digesters may require a NYSDEC air permit, depending on factors such as their horsepower, geographic location and operating efficiency. If the facility has a backup flare in case of CHP downtime, it too may contribute to the need for an air emissions permit. In cases where the digester gas is to be injected into a gas main rather than combusted onsite, the process of cleaning and compressing the gas prior to injection may also generate emissions in amounts requiring an air emissions permit.

Gasification, direct firing and co-firing biomass projects will likely be considered major stationary combustion sources based on the State's definition, and be subject to permitting as such. The difficulty of obtaining permits will depend to some degree on the project location. Projects proposed to be located in a "non-attainment" area may face more difficult and expensive permitting processes, since the emission thresholds for one or more contaminants will be more stringent. A non-attainment area is one not meeting the National Ambient Air Quality Standard (NAAQS) for a specific air containment, such as particulate matter (PM), sulfur dioxide (SO_2), nitrous oxide (NO_2), or ozone.

Tables 5 and 6 provide more information on applicable air emission regulations for new biomass facilities within a particular county or within New York City. In addition to the requirements already noted in this sub-section, ambient air requirements particular to specific counties are addressed in NYSDEC Chapter III-Air Resources, Subchapter C; Air Quality Area Classifications, Parts 260-317.

Table 5. Default Acceptable NOx and VOC Offset Source Areas for Proposed Sources in NYS Based on 1-Hour Ozone Areas.

Proposed Source's location in a Nonattainment or Attainment Area	Appropriate NO_x Offset Source Locations	Appropriate VOC Offset Source Locations
Attainment Area	All of New York State	All of New York State
Marginal nonattainment areas in Niagara-Erie Counties, Jefferson County, and Capital District Counties	All of New York State	All of New York State
Moderate Nonattainment area in Dutchess, Putnam and Orange Counties (excluding LOCMA)	All of New York State	All counties and areas in New York State with Moderate and Severe Nonattainment Classification
Severe nonattainment areas in Rockland, Westchester, LOCMA, New York City, Nassau, and Suffolk Counties	All counties and areas in New York State with Severe Nonattainment Classification	All counties and areas in New York State with Severe Nonattainment Classification

Table 6. Default Acceptable NOx and VOC Offset Source Areas for Proposed Sources in NYS Based on 8-Hour Ozone Nonattainment and Attainment Areas. DAR -10 / NYSDEC Guidelines on Dispersion Modeling Procedures for Air Quality Impact Analysis.

Proposed Source's location in a Nonattainment or Attainment Area	Appropriate NO_x Offset Source Locations	Appropriate VOC Offset Source Locations
Attainment Area	All of New York State	All of New York State
Basic nonattainment areas in Capital District, Buffalo-Niagara Falls, Essex County, Jamestown and Rochester Areas	All of New York State	All of New York State
Moderate Nonattainment areas in Mid Hudson-Poughkeepsie areas	All of New York State	All counties and areas in New York State with Moderate Nonattainment Classification, except Jefferson County
Moderate nonattainment areas in Rockland, Westchester, New York City Boroughs, Nassau, and Suffolk Counties	All of New York State	All counties and areas in New York State with Moderate Nonattainment Classification, except Jefferson County
Moderate nonattainment areas in Jefferson County	All of New York State	All counties and areas in New York State with Moderate Nonattainment Classification

As previously noted, biomass projects proposed for areas within New York City or the New York City watersheds should consult NYCDEP regulations for any additional requirements.

Wastewater Regulations

Biomass facilities may need to discharge permitted process wastewaters generated as part of facility operations. If located in a rural setting, this may entail the expense of on-site pretreatment and/or transportation to a permitted facility. However, in some instances it may be possible to discharge to a surface water body of New York State with the proper permit(s).

If a biomass facility is to be sited in an urban setting, wastewater may be discharged to a sanitary sewer that is part of a permitted conveyance system. This is likely to be a more cost-effective option.

Whether wastewater is discharged to a surface water body or to a sanitary sewer, a New York State Pollution Discharge Elimination System Permit (SPDES) will be required. Farm-based agricultural digester systems using manure feedstocks will sometimes require changes to SPDES permits for the host farm; this is addressed further in Chapter 3, Agricultural Waste Digesters.

If the discharge is intended for a sanitary sewer, the local sewer ordinance law should be consulted for restrictions on the amount and strength (allowed concentration of certain contaminants) of wastewater acceptable. If the discharge is intended for either surface waters or ground waters of New York State, 6NYCRR Chapter X Division of Water Parts 700-750 should be referenced. Additionally Subchapter B of Chapter X Parts 800-940 provides classes and standards of quality and purity that are assigned to major fresh water and tidal salt waters within New York State.

As previously noted, biomass projects proposed for areas within New York City or the New York City watersheds should consult NYCDEP regulations for any additional requirements.

1.4.2.3 Internal Operational Processes

The internal operational processes integral to any proposed biomass facility will produce certain environmental compliance requirements. Internal environmental considerations generally include health and safety concerns pursuant to protecting workers and the internal work space. These are regulated by the Occupational Health and Safety Administration (OSHA, online at www.osha.gov), and local agencies such as the County Health Department. In general these regulations require that equipment is safety-compliant and that operational procedures protect the workers within the work space. Federal right to know laws and emergency planning requirements will precipitate local and state emergency planning needs. These laws must also be satisfied with respect to identifying the location, amount and type of hazardous substances and/or wastes normally present within the building(s) on site. Workers must be properly educated and trained in the handling of, and exposure to, certain materials that may be present as a matter of facility operations. Proper records must be kept and available for inspection. Required health and safety equipment must be kept on site in good working order and in sufficient numbers.

While not a part of the permitting required to develop and construct a biomass project, OSHA and other health and safety permits relating to plant operations will be required to operate a biomass project and should be addressed in the planning stages of development. Early consultations with OSHA and local municipal building inspectors will equip developers to address these responsibilities effectively.

1.5 PERMITTING PROCESSES

1.5.1 State Environmental Quality Review Act (SEQRA)

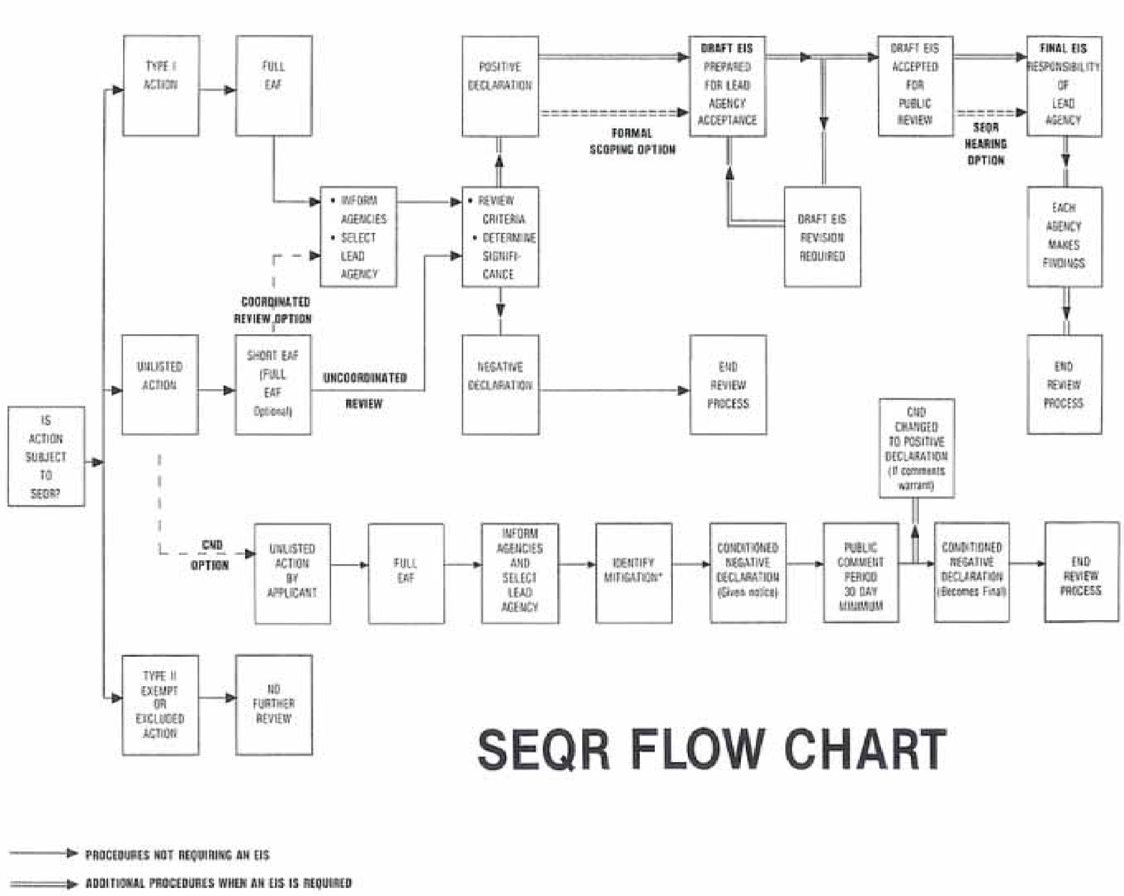
The State Environmental Quality Review Act (SEQRA), set forth in 6 NYCRR Part 617 of the New York State SEQRA regulations, requires that consideration of the potential environmental impacts of a proposed project be incorporated into the planning, review and decision-making processes of state, regional and local government agencies at the earliest possible time. New York City has a separate but similar City Environmental Quality Review (CEQR). SEQRA/CEQR's overarching purpose is to require the review and mitigation of environmental impacts associated with discretionary actions that may be considered by state, regional and local agencies. Thus, SEQRA requires that all agencies determine whether the actions they directly undertake, fund or approve may have a significant adverse impact on the environment. If a determination is made that the action may have a significant adverse impact, then the preparation of an environmental impact statement is required. The general outline of the SEQRA process is provided below; for more specific information, developers should refer to the SEQRA Handbook, which can be found online at www.dec.ny.gov/permits.

SEQRA/CEQR is generally structured to require different levels of environmental analysis based on the nature, scope and extent of the anticipated environmental impacts of discretionary actions. These are generally classified in the SEQRA/CEQR process as "Type I," "Type II" and "Unlisted" actions. Type II actions are those specifically listed actions that are categorically deemed to have no significant impact on the environment or are otherwise precluded from environmental review under SEQRA. Type I actions are those that meet or exceed specified thresholds and, therefore, are likely to have an adverse affect on the environment, such that a full Environmental Impact Statement (EIS) will be required. Actions that are not classified as either Type I or Type II are considered to be Unlisted; these actions require the developer to undertake further environmental analysis. This may range from the completion of a short or long version of the Environmental Assessment Form (EAF) to a full EIS if the potential exists for at least one significant adverse environmental impact as a result of the project. SEQRA sets forth a non-exhaustive list of potential significant adverse impacts. When required, an EIS must address any mitigation measures considered appropriate to mitigate the environmental impact, and the range of reasonable alternatives to the proposed action, including a "no action" alternative.

It is important to note that SEQRA mandates the *procedures* that must be undertaken by government agencies in reviewing environmental impacts – it does not mandate specific *outcomes.* Agencies retain considerable discretion when deciding how to appropriately balance economic and environmental questions (Gerrard, 1997). The statute states that adverse environmental effects of an action will be minimized or avoided "consistent with social, economic and other essential considerations, to the maximum extent practicable."

Figure 5 shows the route through the SEQRA process that a project would follow. Most biomass projects will likely be classified as Unlisted and require a Long Form Environmental Assessment. In that form, the developer would outline the nature of his project from both a site and process perspective. Table 2 summarizes the major types of input data and indicates the types of process and construction data SEQRA requires.

Figure 5. SEQR Flow Chart. Source: New York Department of Environmental Conservation.



The initial direction that a project takes through SEQRA is determined by the lead agency. The local town or planning board usually assumes lead agency status. However, in some cases NYSDEC has assumed lead agency status where a significant environmental impact is anticipated to an area under direct NYSDEC authority (such as a major water body). The same could apply to NYCDEP if city land or watershed areas were potentially impacted.

In SEQRA, both the lead agency and the public play a significant role. Because investigation, documentation and mitigation of potential environmental impacts can represent a major expense for the developer—including inspections and assessments by outside agencies or professionals, the formulation of plans to mitigate potential environmental impacts and multiple revisions to blueprints—every effort should be made to anticipate, and avoid or mitigate, potential environmental impacts prior to beginning the SEQRA process. To this end, developers are advised to involve professional environmental planners and to communicate with local and state officials early in the development process.

For any given project, there will likely be a number of concerns raised by members of the community. Among the issues typically of greatest concern for community members are:

- Construction impacts
- Truck traffic for fuel deliveries and waste removal (dust, road wear, traffic congestion)
- Visual concerns (fuel storage, smokestacks, smoke and vapor emissions)
- Architectural concerns (does the proposed facility fit into the built and natural environment?)
- Emissions (environmental pollutants, health concerns, odors)
- Safety

Steps should be taken early in the planning process to anticipate and mitigate any potential problems in these areas.

1.5.2 Uniform Procedures Act (UPA)

The previously described local and state environmental permitting processes, including building permits and environmental permits, must comply with the Uniform Procedures Act, Article 70 of the Environmental Conservation Law, and the Uniform Procedures Regulations, 6 NYCRR Part 621, designed to provide the public with the opportunity to review applications and participate in permitting, planning and decision making.

The Uniform Procedures Regulations govern the administration of applications for permits submitted to NYSDEC or its agents within the State of New York and dictate such things as internal time requirements for departmental review of submissions, public comment periods, and responses to public/department review comments. For example, NYSDEC is required to act within specific time frames relative to whether projects are considered “Minor” or “Major.” For minor projects, NYSDEC must make a permit decision within 45 days of determining that the application is complete. The general schedule for major projects is as follows:

If no hearing is held, NYSDEC makes its final decision on the application within 90 days of its determination that the application is complete.
If a hearing is held, NYSDEC notifies the applicant and the public of a hearing within 60 days of the completeness determination. The hearing must commence within 90 days of the completeness determination.

As implied by the preceding, an important consideration in the initiation of the process is to insure that each application for a permit is complete. NYSDEC will not commence review of any permit application until it is determined to be complete pursuant to Part 621.4 of the Uniform Procedures Regulations and other related criteria. This part of the regulations also applies to projects that must satisfy the provisions of SEQRA.

CHAPTER 2 - CROSSCUTTING ISSUES: FINANCING

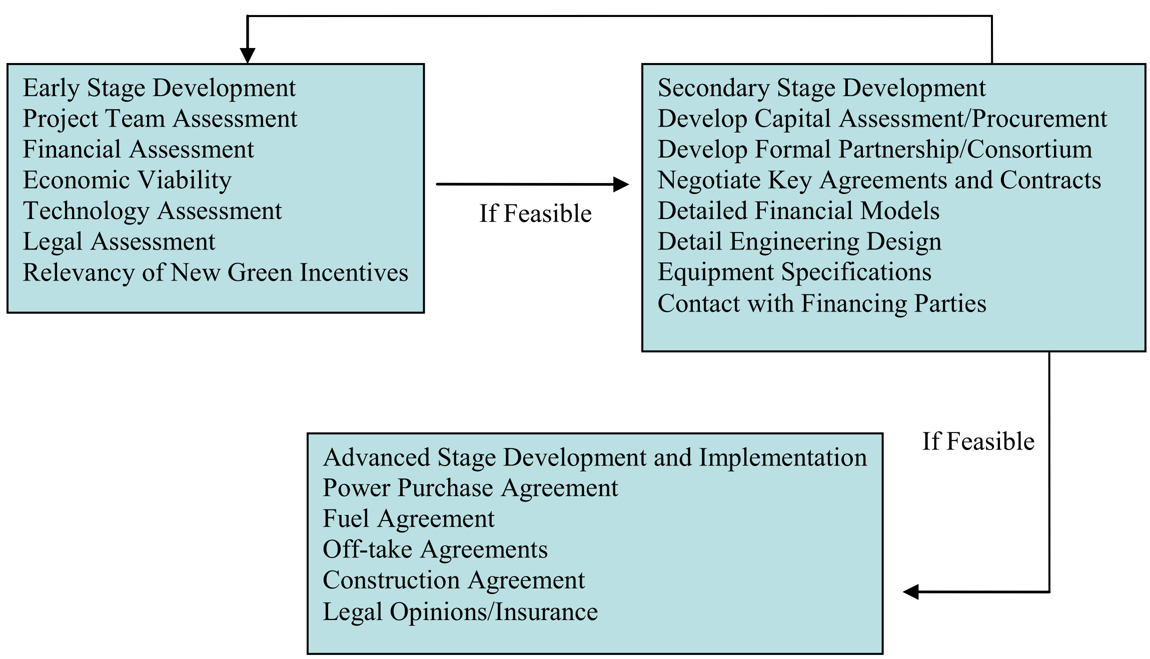
2.1 INTRODUCTION

Financing is a key part of project development, alongside other processes such as biomass resource assessment, site assessment, technology assessment, and permitting. These processes are very much integrated, as the inputs and outputs of each are used by the others. The financing process will result in an assessment of the financial viability of the project. From a financial perspective, the determination of viability is fundamentally reduced to answering the question, "Do the revenues and savings resulting from the project cover the costs and provide an acceptable return to the project developers?"

The purpose of this section is to provide a description of primary steps, key factors, issues, and other considerations in financing biomass projects. This section is not intended to provide a comprehensive and definitive financing cookbook, but to lay out the minimum considerations and identify potential pitfalls that are likely to arise in the development of a biomass project.

It should be noted that the financing process is often not linear. Figure 6, below, shows only one major feedback loop; however, in many cases modifications are made at each stage of the financing process as conceptual/preliminary design approaches are refined, more detailed information is developed, and the requirements of partners and counter-parties are taken into consideration. Feasibility studies may be undertaken in all stages of developing a workable financing approach. This requires an investment, but it may be worth spending money in the beginning to avoid costly mistakes later.

Figure 6. One Major Financing Process Feedback Loop.



In order to make a project viable, flexibility may be required when making decisions about the project siting, configuration, financing and ownership structures. Outside expertise in finance, engineering and contract law can also be helpful in making the best decisions.

The entire process, from an initial resource assessment to the start-up of the plant, may take two years or longer, depending on the complexity of the project. While the ultimate end point may be clear, oftentimes the path leading there is not.

2.2 BASIC STEPS AND INFORMATION NEEDS IN THE FINANCING PROCESS

Identifying and Quantifying Project-Related Costs

All project-related costs need to be identified and quantified. This is usually done using some combination of quotes from providers, past project operating experience, support from qualified consultants, and industry specific data sources. For newly commercialized technologies, assumptions must often be made as actual cost and operating data might not exist. The uncertainty inherent in those assumptions needs to be recognized, and appropriate margins of error built into the project pro-forma.

There are two basic types of project-related costs: capital costs and operating costs. Capital costs refer to site modifications and improvements, equipment, compliance with permits/approvals, and installation associated with fuel supply/transportation/storage/handling, power and thermal energy generation, and energy export/interconnection. Operating costs refer to fuel supply, operations and maintenance, backup and supplemental power.

Calculating Potential Revenues and Savings

As soon as possible in the early stage of financing, all potential revenues and costs savings should be identified. These sources are refined in the secondary stage of development and often secured in agreements in the advanced stages of development.

To qualify for financing, the developer will need to show contracts both for fuel supplies and for electricity and heat sales. Considerable self-investment, and documentation of alternative revenue streams, may also be required. These requirements are briefly discussed below.

Fuel Supply. A fuel supply study and agreement will be needed. In general, the smaller the combustion facility, the less important fuel flexibility is, so long as the facility is not going to be dependent on a single fuel supplier. For larger facilities, fuel flexibility becomes quite important from the point of view of the financier, who wants to protect against fuel price spikes.

If the proposed biomass combustion facility is to be collocated near a biomass supplier, such as a farm or mill, financiers will want to see a commitment from the biomass supplier. If collocation is not planned, project developers should be able to show due diligence in researching their proposed biomass suppliers; sources should be identified, the consistency and longevity of these supply chains should be specified, and fuel supply contracts should be in place whenever possible. Such due diligence will be less important if the biomass supplier is a farmer growing perennial crops, who can provide contracts, leases, and a long-term supply agreement.

In general, biomass combustion facility developers should be able to show they have a reliable and long-term supply of fuel that will not be subject to disruption due to adverse weather, market shifts or changes in government policies. Banks may be wary of loaning money to a project that relies too heavily on government incentives for its fuel source, or for its revenue streams.

With regard to project design, some financiers will also want to see a backup system on site, such as a natural gas or diesel generator, although as financiers become more familiar with biomass-fired systems and biomass supply chains, they are less likely to view a backup system as a necessity.[8]

Energy Offtake. A project should have solid offtake and interconnection agreements that can be scrutinized by financiers. Most financiers who know about biomass technology are coming to the conclusion that CHP or cogeneration is needed to make most projects viable; thus, they will want to see a heat purchase agreement.

At this writing, credit markets are tight due to the global financial crisis of 2008-2009. In this financial environment, it is more necessary than ever to have offtake agreements to sell the electricity, heat, RECs, and other products that will be produced by the facility. Uncontracted facilities are unlikely to qualify for loans (Benson, 2009).

Additional Revenue Streams. If revenues rely on sales of RECs, fiber or other coproducts, tipping fees, or other secondary sources, the developer should be able to show contracts for these revenue streams; in the absence of a contract, market research should be provided to show why a contract is not needed. Government grants or incentives should also be well documented if they are included in project revenue streams. Documentation should also be provided showing that the host site or facility has made a long-term commitment to the project.

Self-Investment. Financiers may look for a demonstrable commitment of investment cash from the developer or from a major investor, or both. A sizable self-investment demonstrates that the developer has significant "skin in the game" and is personally committed to the success of the project. The amount of self-investment to be provided up-front by the developer will depend on many variables. In the current financial climate, with credit difficult to obtain, the developer should be prepared to provide dedicated grant money and investments amounting to around 50% of total project financing.

A more in-depth discussion of several of these points follows.

Incorporating Renewable Energy and Biomass Incentives into Financial Models

The role of financial incentives can be significant, especially for biomass projects generating electricity. That includes investment and production tax credits (ITCs and PTCs), renewable energy credits (RECs), accelerated depreciation schedules, favorable prices for exported energy, and considerations in greenhouse gas (GHG) emissions trading programs. Renewable project development has historically been closely coupled with production tax credits. However, note that the 2009 American Recovery and Reinvestment Act (ARRA) permits owners of PTC facilities, including biomass, to take a 30% federal ITC when the project is placed in service, instead of the 10-year PTC. This ITC is based on the cost of the facility. ARRA also provides an additional option to take a US Treasury department cash grant in lieu of the ITC.[9] For more details on the ITC, go to www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&State=federal¤tpageid=1&ee=1&re=1.

At the time this is written there is no federal mandate regarding carbon trading in the U.S., although several trading models have been proposed and are under consideration. At the state level, New York is signatory to the North East Regional Greenhouse Gas Initiative (RGGI), a mandatory cap and trade system focused on major emitters of greenhouse gases in the power generation industry, which is supported by nine

[8] Heat purchasers may also want to see a backup system in place.

[9] Treasury is to provide grants covering up to 30% of the cost basis of qualified renewable energy projects that are placed in service in 2009-10, or that commence construction during 2009-10 and are placed in service prior to 2013 for wind, 2017 for solar, and 2014 for other qualified technologies. Applications must be submitted by October 1, 2011, and the Treasury is required to make payments within 60 days after an application is received or the project is placed in service, whichever is later. The grant is excluded from gross income and the depreciable basis of the property must be reduced by one-half of the grant amount.

northeastern states. Under this initiative, emitters can choose to reduce emissions to agreed target levels by investment in process technology; alternately, they can choose to buy emission reduction credits (ERCs) from companies able to generate an excess beyond their target reduction, or from "approved, registered" projects, such as renewable energy projects, that can demonstrate an overall reduction. In the latter case, the approval has to be validated against an independently recognized protocol and be verified annually by a third party. New York State projects wishing to sell ERCs into the RGGI system will need to use the RGGI Model Rule Protocol. This protocol follows the principles of the World Resources Institute (WRI) Greenhouse Gas Protocol and is considered to produce projects that are highly credible in terms of greenhouse gas emissions reduction.

In general, the choice of which protocol to use will depend on which market the project wishes to sell its green attributes into. Several other protocols besides the RGGI Model Rule may be applied. The California Climate Action Registry (CCAR) protocol is modeled closely on RGGI and the Chicago Climate Exchange (CCX) standard is another that is often quoted, though it is considered less rigorous by some observers in terms of project qualification.

The process of registering a project, and verifying the creation of emissions reduction credits, is not without cost. There is an initial registration and project verification fee, which can be substantial; in addition, there is an annual verification fee. If ERCs are anticipated as a revenue stream, these costs must be calculated and included in the overall financial evaluation of the project.

It is advisable to decide at an early stage of project development whether or not ERCs will add value to a project. There is no requirement for a project to claim ERCs, however, if the developer is considering revenues from the sale of ERCs as part of the overall project pro-forma a model should be developed. It should clearly demonstrate all the requirements of the protocol, show the relevant assumptions based on the actual project operation, and include supporting information for price assumptions. It is also important to include ERCs in all contracts, which should recognize that ownership of the ERCs is established at the point at which they are created.

Sale of ERCs

Since there is as yet no mandated scheme beyond RGGI, the developer may have to look to the voluntary sector to create a market for ERCs. There are several companies that specialize in buying and selling ERCs. Some of these simply trade in credits, while others extend their involvement to financing and investing in projects designed to generate ERCs. (A simple Internet search for carbon credit traders will identify a host of such companies). The market for the credits consists largely of those companies and institutions that are regulated, or anticipate the imposition of legislation; those that are pressured by Non Governmental Organizations (NGOs) or shareholder activists intent on "cleaning-up" their environmental impact or improving their environmental stewardship; and those being driven by consumer pressures to provide an "environmentally friendly" alternative to current product offerings. In any case the ERC traders are looking to match buyers with sellers. This leads to an interesting choice for the developer.

Early pioneers in the U.S. carbon markets were companies that had successfully developed businesses trading ERCs in those countries signatory to the Kyoto Protocol. Many saw the U.S. as the next big emerging market and sought to replicate their business models here. Typically these companies will offer an up-front amount per ERC for a fixed period, and this can be attractive to a developer seeking additional sources of project equity. With a term sheet in hand, this can be useful for negotiations with lenders or other investors. These deals typically favor the buyer of the ERC, who is betting on the market price rising in the future.

However, a different business model is now emerging that addresses the concerns of developers, who would prefer not to lock in a price today, thus leaving room for participation in future market price increases. There are several variations on this theme, most of which set a floor price and a formula for sharing in future increased revenues. The choice of price and contract type is important, as it will have an impact on project development and the overall financing structure.

Securing Energy Off-Take Agreements

A Power Purchase Agreement (PPA) is a long term contract between a generator of electricity and a purchaser of electricity. The generator could be a private developer or a public entity such as a city or county. The purchaser could be an investor-owned utility, a municipal or rural electric cooperative utility, a publicly owned utility, or wholesale or retail customers in unregulated markets as off-taker of the electricity. The PPA provides a steady stream of revenue to the generator for a fixed term, which is a necessary component to financing the construction and operation of the generation facility.

Regardless of the generation technology, a power purchase agreement covers a number of complex issues, including the price of the electricity, the length of term, the commissioning process of the generation facility, milestones related to construction, permitting and operation, issues related to the transmission of electricity, interconnection agreements between the generator and the distribution utility, provisions that curtail the production of power under authority of a transmission entity, default and damage provisions, credit commitments, insurance provisions, early termination rights, and provisions that govern the ownership of environmental attributes, credits or certificates (Yarano, et. al.).

Guidance documents on PPAs are available from utility commissions, other governmental agencies and independent organizations, but ultimately a PPA is a complex binding legal document that requires professional legal counsel.

Because PPAs create a revenue stream, lenders will evaluate the duration of the contract, the creditworthiness of the utility or developer, and the penalties for breaching the contract. In some cases utilities may be the primary purchaser of exported power. This may be driven by capacity needs, but more likely will be due to requirements of the state's renewable portfolio standard (RPS). This is discussed in greater detail below.

In some cases, facilities will also negotiate thermal offtake agreements to sell steam or hot water. Lenders will want to see legal contracts for these offtake arrangements as well.

For more technical information on energy offtake, see Chapter 3 – Crosscutting Issues: Electrical, Thermal, and Gas Offtake Issues.

Financing Models

There are two types of financing: debt and equity. Debt financing involves taking a loan or issuing a bond to provide capital that must be repaid. Equity financing entails sharing ownership and/or revenues with an investment partner or partners.

Most large-scale projects prior to the 2008-2009 financial crisis had been structured with a mix of debt and equity, typically 40%-70% debt, using non-recourse financing (meaning that the loan is secured by the project itself as opposed to some other type of collateral). At this writing, much higher equity percentages are required for all capital projects due to the unavailability of debt financing that resulted from the financial crisis. Coupled with the general economic downturn, the scarcity of debt financing has negatively impacted the renewable energy market.[10] Lenders to recent smaller biomass projects have required pre-tax cash flow to be 10% greater than expenses plus debt service.

In general, the amount of equity financing and cash flow required by lenders will vary depending on national and regional economics; project developers are well advised to research current conditions, so they will know what to expect when meeting with potential financiers.

[10] The recently passed federal stimulus package (American recovery and Reinvestment Act of 2009) includes major modifications to the federal tax incentives for biomass and other renewable energy designed to address the credit crisis facing the renewable energy industry. Those incentives applicable to biomass projects are discussed in the economic evaluation appendix to this guidebook.

When seeking debt financing, the following is typically needed:

- A resource assessment (for example, a comprehensive fuel supply study with supply/price curves generated for multiple alternative suppliers conducted at the site)
- Long-term fuel contracts, if possible
- A project feasibility study (technical and economic evaluation) by a credible consultant
- Proven expertise in managing the type of project to be financed or an agreement with a qualified third party project manager
- A development team that includes members with experience in key elements of operations (including experience in small business management, energy generation development, contract negotiations, biomass, and in dealing with utilities).
- Zoning and site permitting approval, including environmental impact studies
- Equipment performance data
- Equipment warranties and an operations and maintenance agreement
- A completed electricity interconnection study
- A long-term power purchase agreement (at least 10 years, preferably 15) with a creditworthy utility that will purchase the electricity at specified prices
- Thermal offtake agreements if the facility is to sell steam or hot water
- Commitments for all required equity
- A business, financial and risk management plan for the project including complete pro-forma financial statements
- Investment dollars amounting to around 50% of total investment[11]

Risk Assessment

There are risks associated with biomass projects that must be considered when applying for debt financing. These include fuel supply risk, market risk, technology risk, and operational risks if the project is closely aligned with a third party industrial customer/partner. In general, for any capital project, the greater the risks, the greater the return required by those financing the project.

Fuel supply risk for biomass projects in New York State can be difficult to address, because fuel supply chains are not well developed, and demand is anticipated to increase. Biomass projects generating their own feedstocks, such as wood or paper mills, or livestock operations, may be subject to less intensive scrutiny of fuel supply than those reliant on external suppliers; the latter can manage their risk to some extent by securing fuel supply contracts prior to applying for financing. Relying on a single external fuel supplier may be viewed as risky behavior, however, and it is advisable to identify fallback fuel sources.

Market risks include both volatility and unexpected increases or decreases in the prevailing local and regional prices for electricity (or gas, for agricultural digesters selling gas to a user or into a utility pipeline). Market risks can also include the unpredictable value of renewable energy credits and other "green" attributes that may be included in a project's revenue stream.

Technology risk continues to be an issue for some biomass projects using newer technologies that have not been widely demonstrated. These projects will present risks for installed costs/construction schedule, maintenance, reliability, and even emissions compliance, all of which will be manifested in higher costs from system integrators, maintenance service providers, vendors of other equipment that must be coupled with the new technology, and engineering, procurement, and construction partners. In the absence of full scale demonstrations that adequately document performance, equipment guarantees will be changed and in some cases not applicable. Often, more time in the regulatory process will be required as agencies not familiar with the technology will have to be educated and brought up to speed.

[11] This level of self-investment is higher than would normally be required due to the tightness of credit markets at the writing of this guidebook. As the supply of credit increases, the required level of self-investment should fall once again.

Operational risk can be related to technology risk, but is mostly present when operations of the biomass energy project are closely linked with those of an industrial or other large energy consumer. For example, if a large industrial steam purchaser no longer requires steam due to changes in its own operations, the rate of return and estimated profitability of the biomass project can be significantly impacted.

The bottom line is that risk analysis depends on the financing parties' opinions about risk. Some lenders may make a higher risk assessment due to their unfamiliarity with renewable energy technologies. A loan guarantee offered by a government agency can reduce the risk for the lender and increase the potential for a project to be financed. There is a federal Department of Energy (DOE) Loan Guarantee Program to which biomass projects employing innovative technologies may apply.[12]

Demonstrating Cash Flow

It is important to be able to demonstrate cash flow sufficient to meet the expected payback period. To do this, all financial considerations and development/operational steps are compiled and integrated into a project pro-forma statement illustrating cash flow over the life of the project. The resulting financial picture must be acceptable to all partners involved in financing the project, e.g., project developers, equity investors, and lenders. The key financing considerations for biomass projects are summarized in Table 7. For more detailed information about developing a pro-forma statement, see Appendix 3.

Table 7. Summary of Key Factors to Consider in Financing Biomass Projects.

Project Developer	Experience and expertise of management team
	Corporate prior projects
	Corporate current projects
Project Status	Status of key agreements (fuel supply, power and thermal energy sales, engineering/procurement/construction)
	Status of required permitting and approvals
	Schedule to complete project
	Local support for project
Economics	Non-recurring capital costs
	Operating costs
	Forecasts for revenues (electricity, steam, tipping fees for waste-fueled projects)
	Revenues from environmental attributes (REC's for regional cap and trade and voluntary markets, emissions credits, and offsets)
	Forecasts for cash flow and assumptions (equity, debt, lease financing)
Power/Steam Sales	Terms of contract, agreements, or tariffs
	Utility, power purchase agreement with industrial customer, or regional wholesale market
Engineering Feasibility	Design, technology, and costs
	Site Suitability
	Fuel requirements
	Electrical interconnection
	Environmental impact and compliance approach
	Emissions control
	Energy purchaser load profile
	Water supply and discharge
	Maintenance schedule and availability requirements
Fuel Supply and	Fuel contract term and supply

[12] The U.S. DOE's Loan Guarantee Program authorizes the Secretary of Energy to make loan guarantees to qualified projects. The program works by issuing technology-specific solicitations; in the first round of the program, ten specific technology areas were specified, including biomass. The program was established under Title XVII of the Energy Policy Act of 2005, and at this writing is being modified to streamline the application and approval process.

Resources	Supplier credit worthiness
	Alternate suppliers
	Heat content and constituencies
	Coordination with other contracts
Engineering/ Procurement/ Construction Partner	Qualifications, experience, creditworthiness,
	Terms of contract – schedule, guarantees, bonuses, penalties
Legal and Regulatory	Site control/property rights
	Permitting
	Environmental Liability
Stage of Financing	Financial structure
	Partners and sources of funding
	Timetable to close
Risk Assessment	Credit risks of energy purchaser, fuel supplier, and EPC
	Financial risks – interest rates, inflation
	Market and operating risk
	Legislative/regulatory risks

2.3 STAGES OF FINANCING

The financing process may be broken into three stages: early, secondary, and advanced (see Figure 6).

2.3.1 Early Stage Development

Assessment of project team

Potential lenders and equity partners will want to obtain a fair assessment of the project team, including the developer, energy purchasers, fuel supplier, engineering procurement and construction contractor (EPC), operations and maintenance supplier, etc.

A project team may be small or large, depending on how much of the predevelopment and development work it will take on. The easiest and simplest approach is to hire an outside firm to plan and build the facility. Some firms may also be contracted to take over ongoing operations and maintenance tasks once development is complete, selling heat and electricity back to the facility owner at an agreed-upon price.

At the other end of the spectrum, the facility owner may elect to develop the project in-house. In this case, a number of team members must be brought on board or contracted. The set of skills needed may include:

- Engineering/Facility design
- Architect
- Planning
- Financing
- Feedstocks procurement
- Contracting
- Operations and maintenance
- Community relations
- Permitting

Technical feasibility

The developer may have made assumptions concerning the project's feasibility and equipment configuration in order to generate a preliminary financial model; however, once the decision has been made to proceed with the project, technical feasibility studies need to be undertaken. The original plant configuration used in preliminary modeling may have been generic for estimation purposes, but now the developer will need to address site-specific issues related to design and equipment selection. Ambient air temperature, humidity, geology, geographic features, fuel delivery systems, site access, and electrical interconnection requirements all need to be taken into consideration.

Preliminary contract negotiations

The developer should have enough information to begin preliminary contract negotiations in an informed manner.

The Power Purchase Agreement (PPA) is a critical aspect of the project as well as the cornerstone of the developer's ability to raise development capital. The importance of securing at least a preliminary version of the PPA cannot be overstated. Fuel supply and land use agreements, while important, are relatively mundane compared to the PPA. The key terms of the PPA are the power price and the term of the agreement. In addition to pricing of energy and capacity payments, the developer needs to address other elements in the PPA, including hours of planned operation, transmission and substation issues, performance penalties and bonuses for performance, metering, payment schedule, escalation. In addition, the ownership of environmental attributes of the energy sold under the PPA need to be explicitly stated and understood by both counterparties.

For any excess power to be exported from the project, access to the electricity grid is very important. This requires negotiations with the local electric utility and in some cases regional transmission operators. Depending on the size of the project[13] and the utility service territory, the technical and process requirements for grid interconnection will vary. Small projects, e.g. anaerobic digesters, cannot stand to bear excessive costs for switchgear, automated disconnection or energy storage. Standardization of the interconnection process and associated technical requirements has been a topic that the distributed energy, CHP, and renewable energy industries have been trying to address together with electric utilities and state and federal electricity regulators. The interconnection standards and requirements process continues to evolve as the penetration of distributed energy resources increases.

In addition to electricity, some projects may export steam or hot water. These revenue streams will be important and must be formalized by contracts.

Most projects will also need to negotiate fuel supply contracts. These should be made on a competitive basis. Most biomass projects will need backup or alternative fuel supply plans as well as primary contracts.

Cost Estimates

Once the developer has conducted a technical feasibility study, and concluded preliminary agreements with project partners, as well as the PPA and fuel supply contracts, these elements can be used as the basis for refining overall project cost estimates. To do this, the developer must acquire the best and most current available data on project costs.

Financial Model

Using the best estimates of all project related costs, the developer is in a position to flesh out a preliminary model and work toward a greater degree of detail and accuracy. The model should be set up so that variables may be easily changed to allow for running various scenarios and sensitivity analyses.

[13] The threshold for a more rigorous set of interconnection processes, both technical and legal, is 20 MW. This guidebook focuses on projects of around 10 MW and smaller.

Provisions for debt should now be built into the model. After running equity scenarios, additional scenarios may incorporate senior debt, subordinated debt, vendor debt, lease financing etc. If the developer does not know the kind of debt available, conservative estimates may be used to produce a simple debt financing analysis.

Initiate Permit/Approval Process

Analysis done by the developer and/or joint venture (JV) partner should provide a good indication of whether a workable deal is in the making. If it is, they will also have a good understanding of the necessary permitting process and risks and should begin the initial steps in that important, concurrent process.

Once the developer addresses early stage development tasks outlined in this section, the necessary information should be available for use in writing a project briefing introducing the project to prospective participants.

2.3.2 Secondary Stage Development

Identifying Potential Financing Partners

Once the developer has decided to raise development capital, additional partners must be identified; these partners will contribute the necessary resources. The choice of new development group partners is critical, because equity investors and banks will scrutinize the qualifications of all project participants. Potential equity partners include other developers with substantial balance sheets, engineering procurement and construction (EPC) firms, equipment vendors, or O&M firms. In most cases, the developer must be willing to carve out a sufficient portion of the upside financial benefits to attract new partners.

Detailed Engineering Design and Feasibility

Design and engineering feasibility must proceed to a more detailed level. Keeping in mind the requirements of finance, the developer should work with established engineers and companies that investors and banks will accept. As the project moves through the advanced stages of engineering, adhering to environmental compliance is a necessity. Thorough communication with the proper agencies and knowledge of regulations is critical.

Detailed Financial Model

The financial model should include more detailed information on project engineering, operating parameters, and the PPA. The developer should update the data in the model including finance, working capital fuel and initial fuel supply reserves, start up and run costs, transmission and grid connection charges, taxes, and contingency costs.

The model no longer serves just as a tool for the developer, but will be closely scrutinized by increasing numbers of parties who will demand a higher degree of thoroughness and accuracy. The development team should have an in-house project finance expert, or contract for the services of one.

Progress on Project Agreements and Contracts

The developer should be negotiating several iterations of agreements as better data becomes available and the parties to the agreements begin to understand the limits and constraints of the project. Potential financing will require that all the key contracts are either in place, or are pending final agreement prior to financial closing. It will be desirable to have firms that have an established, recognizable track record and solid balance sheets to back up performance of all aspects of the contracted work or service. For EPC contractors this means the experience and financial wherewithal to perform the contract as well as cover damages resulting from failure to perform. Equipment manufacturers must be able to back up guarantees on equipment performance. O&M firms should enjoy an established reputation, and have experience related with the project's plant configuration. Developers must be careful not to get locked into technologies or equipment that may subsequently prove to be inappropriate, or that will make them reliant on a single fuel supplier.

2.3.3 Advanced Stage Development and Implementation

Finalize Agreements

The developer is no longer working with project contracts and approvals in their preliminary form. These documents and approvals should be near completion.

Soliciting Equity and Debt Financing

With a well developed project and with documentation that the process to date has been thorough, the developer approaches investors and lenders. Sources of finance include private equity investors, larger developers, commercial banks, and institutional funds. Confidentiality and non-circumvention agreements should be signed before the developer releases detailed project information to any party.

Due Diligence Process

Once the interest of qualified financing sources is generated, these parties will begin the process of due diligence. This process typically takes much longer than expected and can easily run more than six months or even a year. The more thoroughly the developer has addressed and documented all the development tasks, the more quickly financiers will be able to analyze the project. However, the due diligence process, even for the best projects, is rarely without snags. Financiers will find flaws that the developer must remedy before further investigation is pursued. The developer should seek to have the funding source identify all its major concerns from the outset, as this will aid scheduling and budgeting for activities related to addressing these concerns.

Negotiation of Finance Terms and Final Closing

When potential funding parties have completed an advanced but not complete level of due diligence, they will present the developer with proposed transaction terms. Once the financing source drafts specific terms for the financing, i.e., term sheets, negotiations may take place within a range of parameters. Services of financial and legal advisers are generally essential in negotiations at this point. Once all agreements, approvals, legal documentation and negotiations with financing parties have been accomplished, all that remains is financial closing. In practical terms, the developer should not consider the financial closing complete until funds are made available.

Project Construction and Commissioning

This task is left to the EPC contractor and equipment suppliers. Construction financing proceeds in stages and the lenders' engineer will need to sign off whenever additional funds are released. Generally, a contingency fund is required and the project owners must thoroughly review any change orders or cost overruns for which they will be held financially responsible. Electrical interconnection and provisions for the delivery of fuel supplies need to be ready by the time the plant is complete. If the developer has signed a turnkey contract, the EPC firm will usually have performed the initial start-up and plant testing before the contract is considered complete. Once plant performance has been demonstrated to meet agreed upon specifications and accepted by the developer, an O&M firm may take over plant operations responsibilities (unless the developer is also acting as operator). The O&M firm and EPC contractor will work side by side during the transition period to facilitate testing and a smooth transfer of operations.

Ideally, during the commissioning period, power is sold to the buyer under terms specified in the PPA. If the project is selling to a utility, synchronization with the grid is a coordinated effort between the plant operators and the electric utility. Once startup, testing and owners' acceptance of the plant is accomplished, the development phase is over and the project moves into the operational period.

2.4 New York's Renewable Portfolio Standard

New York State's RPS includes incentives and requirements for renewable energy projects, including biomass technologies. It is very important to understand the requirements a project must meet in order to qualify under the RPS. For some projects, only a portion of energy generated will qualify, and this portion may vary with variations in the quality and type of feedstocks and fuels used.

For more information on the RPS as it relates to financing, see Appendix 3: Evaluating Economic Viability. It is also recommended that any project developer be familiar with the NYS RPS Biomass Guidebook, available online at www.nyserda.org/rps/RPS_Biomass_Guide.pdf.

CHAPTER 3 – CROSSCUTTING ISSUES: ELECTRICAL, THERMAL AND GAS OFFTAKE

Because many biomass projects at the scale addressed in this guidebook will be CHP projects, it is reasonable to assume that many will supply a host facility with heat and electricity. This chapter addresses issues pertaining to thermal and electrical interface and offtake and, in the case of some agricultural digesters, gas offtake.

3.1 Host Facility Electrical Load Profile

Assuming that an existing facility will host the biomass project, the developer will need to evaluate the host's electrical profile, as well as the parasitic electrical load that will be required to operate the proposed biomass facility and genset. The examination of utility bills reflecting existing site electrical usage can provide much useful information when undertaking this evaluation.

Some considerations are:

- Where is the site located relative to the source of main electrical supply, i.e., is it near the end of a distribution line where the amperage may be low?
- What is the capacity of the electrical service on site?
- What is the type of service voltage on site, i.e., single phase or three-phase? If three phase, what type of three phase service exists?
- Does the power on site appear to comply with code requirements?
- How is the on-site electricity distributed?
- Does standby power exist and to what extent?

Host sites don't typically use electrical power on an even basis. There is usually a base load and a peak load. The peak load reflects the largest electrical demand during a normal operational day. These variations in electrical demand need to be understood and tracked, usually over a year, so that seasonal demands can be determined. Also, daily and yearly average consumption need to be quantified. Systems that draw large amounts of energy on site need to be identified and the electrical distribution system understood. This evaluation will allow the developer to understand the strengths and weaknesses of the existing electrical system and how it operates from a base system standpoint. The proposed biomass facility location can be graphically overlaid to better understand what electrical system improvements will be required.

3.2 Biomass System Electrical Load Profile

In addition to the electrical requirements of the host, a biomass system will have its own electric load profile, which will include a base load and a peak load component. It should be possible to roughly calculate this load profile from information provided by system component manufacturers. For established technologies, where there is substantially similar previous experience, there may be general rules. For example, a good general rule for anaerobic digesters is that the baseline electricity required to operate a new complete mix digester is about 5% of the electricity it is capable of producing. If one includes post digestion operations, such as solids dewatering, then the electrical consumption of the digester system rises to about 8% of the electricity produced. Keep in mind that such ballpark figures will vary by manufacturer, and will not take into account many site-specific variables such as fuel specifications, operating constraints and loads imposed by peripheral equipment.

Adding the host site's electrical load to that of the proposed biomass facility will yield the total design load for the site. Critical systems can then be identified, and, if necessary, a backup power unit can be sized to carry the critical load.

3.3 Thermal Load Profiles

Just as with the electric load profile, the existing site and the proposed biomass facility may both have thermal loads, and these should also be profiled. Host site thermal loads will likely vary considerably with the season; therefore, a full year's worth of operational data is essential for proper system design. Determinations of average and peak daily thermal loads will help the developer better understand existing site demands and what systems require the most heat.

It is likely that existing thermal loads are being satisfied by a variety of fossil fuel sources. Propane, natural gas, and fuel oils are usually the fuels of choice. Again, records from fossil fuel suppliers can be useful in characterizing the historical thermal loads of the site. Once the host site thermal loads and fuels are determined, the most economical uses for the heat from the proposed biomass facility can be decided.

3.4 Electric and Thermal Offtake

3.4.1 Electric Offtake

Electrical power produced by the system may either be consumed at the host site, sold onto the electric grid, or both. If electricity is to be sold onto the grid, this may be accomplished through third-party contract sales or, for farm-based biogas projects, through net metering. The nature of the interconnection between the biomass facility and the electric grid is typically decided as part of the project planning process.

Third party sales may take place under a bilateral contract. Typically a licensed power broker will act as an intermediary to manage a contract to buy and sell the power, including daily scheduling of the load from the system onto the grid. In some cases, where the load exceeds 1 MW, the power can be exported subject to minimum conditions across state boundaries (See RPS Guide for Biopower Projects).

Net metering is a process by which the host site sells excess power (beyond the needs of the host) to the utility at an agreed rate when the system is producing electricity. When the biomass system is not producing electricity the needs of the host are supplied by the utility. Credits are applied to the host account ($/kWh) by the utility for power delivered from the host. The total is trued-up at year end and the owner of the system either receives a check or an invoice for the net account balance. Recent changes to net metering laws in New York allow net metering biogas facilities up to 500kW in size (farm-based systems only). For more information on the economics of net metering, see Chapter 2 – Crosscutting issues: Financing.

3.4.2 Electrical Interface

In cases where the biomass facility will be selling power to the local electrical utility, the electric offtake interface between the biomass system and the utility is one that requires planning and design coordination. The utility should be contacted early in the planning stages of the project, so the developer can gain an understanding of the limitations of the local grid infrastructure, as well as the magnitude and cost of any needed improvements. For example, the electrical lines in the vicinity of the CHP unit(s) producing the power must be sufficiently sized to handle the loads being generated. In addition, the electrical impedances between the electrical supply source and the receiving entity must be matched. At least part of the costs of any needed utility-side upgrades will be borne by the system operator, and are therefore an important part of the overall financial picture of the project.

The determination of who bears the costs of such upgrades is in part a function of the amount of electricity anticipated to be supplied to the utility. The Net Metering Program regulations of the NYS Public Service Commission limit to $5,000 the cost a utility may charge for electric system upgrades needed to accommodate net metered CHP generators having a maximum capacity of 500 kW. However, some interpretations of these regulations, which are being argued before the NYS PSC at this writing, would allow utilities to charge much more under certain circumstances.[14] The outcome of the case currently before the PSC will likely have a significant impact on the cost, to farms, of future net metering projects.

If the generating capacity is greater than 500 kW, the utility's engineers would have to study the capacity and restrictions of the grid infrastructure at that location to determine whether upgrades would be required before the generation capacity could come online. At generating capacities larger than 500 kW, the cost of any required grid upgrades would be the responsibility of the biomass system owner.

In rare cases, the biomass plant and its host may elect to become an island, disconnected from the local utility. In this case, a backup generator is essential to provide power to the site when the biomass system requires repair or service. The usual configuration, however, is an interconnection that allows electricity to flow between the utility and the anaerobic digester facility.

It is important to note that New York State law supports net metering on one meter per customer. However, many farms have multiple electric meters. This can significantly limit the value of net metering on farms, since the amount of electricity that can be net metered will be limited to the amount flowing through a single meter.

3.4.3 Thermal Interface

Thermal energy generated on site will almost always be used on site or nearby, due to piping costs. The amount of heat needed will influence, to a great degree, the design and size of the system.

If heat is to be sold to satisfy another entity's heating or cooling requirements, it will probably need to be modified to meet the end user's system specifications (such as temperature, pressure, and moisture content). This is an issue that would be addressed in the purchase contract.

3.5 Pipeline Gas

For larger anaerobic digester facilities with gas production potential approaching 1.5 MW electric equivalent, direct injection of gas into utility gas pipeline may be a viable economic option. The pipeline would need to be reasonably close to the digester, and the digester gas would have to be cleaned, enriched to a value of around 95% of the BTU value of natural gas, and compressed before it could be introduced into the pipeline. Scrubbing and compression are the most expensive of these processes. The specific gas acceptance conditions will depend on the utility involved and the tariffs under which they are operating in that geographic service area. The local utility should be contacted in order to ascertain the requirements under which they would accept the digester gas and to negotiate the required metering and related physical equipment that would need to be installed.

In some cases, where the digester is located near a large gas consumer, it may also be possible to sell the gas directly to the consumer for combustion.

If gas is to be sold, it must be prepared to the end user's specifications. This likely means compliance with such parameters as:

- Injection gas pressure
- BTU content

[14] At this writing, several farms have appealed to the NYS Public Service Commission for a generic ruling on how much utilities may charge farms for electrical system upgrades needed to accommodate on-site generation. Although the law appears to cap these charges at $5,000, the law may allow utilities to charge much more if the amount of electricity to be net-metered exceeds 20% of the rated capacity of the local feeder line. The utility in the case currently before the NYS PSC argues that the digester owner should be responsible for $141,000 in upgrades needed to facilitate net metering. The case is known as the Boxler case. Documents in the case may be accessed online at http://documents.dps.state.ny.us/public/MatterManagement/CaseMaster.aspx?MatterSeq=32013

- % oxygen
- % moisture vapor
- Presence and amount of trace contaminants

These issues would be addressed in the gas purchase contract.

CHAPTER 4 – CROSSCUTTING ISSUES: FEEDSTOCKS AND FUELS

This chapter discusses feedstocks and fuels for biomass gasification and direct or co-fire projects. Feedstocks for anaerobic digester (biogas) projects are specific to that technology and are addressed in Chapter 5, Agricultural Digesters.

4.1 Feedstock Sourcing

4.1.1 Wood

In most areas of the state, the available biomass feedstock for gasification or direct combustion/co-fire applications will be wood.[15] There are several varieties of wood fuels available, and the design and efficient operation of a wood-fed biomass facility requires a detailed understanding of specific wood sources, types, growing and harvesting methods, and preprocessing. Once adequate resources within reasonable proximity to the plant are identified, their availability must be secured with supply and transportation agreements. In many cases, there may be tradeoffs to be considered, such as the additional cost of facility design and maintenance to achieve feedstock flexibility, versus the additional risk of relying on too narrow a range of feedstocks. Such tradeoffs will need to be decided early in the development process, and this will require a thorough understanding of what feedstocks and fuels are available, when, in what form, and at what price. See Chapter 2 for a more detailed discussion of the importance of securing fuel supplies in connection with project financing.

There are three categories of wood that may be used as biomass feedstocks:

- Waste wood (urban wood waste (municipal solid waste, or MSW), mill residues, and wood waste streams from other industries)[16]
- Forestry products
- Dedicated woody energy crops, often referred to as short rotation woody crops (SRWC), such as hybrid poplar and willow

These feedstocks are discussed in more detail below:

Waste wood

Waste wood is usually the lowest cost option for biomass fuels. Including transportation and processing costs, waste wood generally sells for significantly less than forestry products or energy crops. Biomass-fed facilities located near urban centers, or near other sources such as sawmills and paper mills, may be able to purchase waste wood in quantity.

"Urban Wood Residues" is the term widely used to refer to wood waste present in municipal and commercial solid waste. Urban wood residues can include packaging materials, furniture and appliance cabinets, and other forms of urban waste that are primarily wood. However, urban wood residues typically consist largely of C&D (construction and demolition) wood or pallet wood, which can be obtained from

[15] Pelletized grass is emerging as a fuel for residential applications, and experiments are being conducted with preprocessed grasses in industrial scale applications; however, grass will likely not be a commercially available feedstock in New York State for some time. Alternative biomass feedstocks, such as food processing residues or manure, may be available in specific situations where the end user (the biomass facility) is located close to the source of these feedstocks. However, the use of such feedstocks is not expected to be widespread in New York. See Appendix 2: Resource Assessment, for more detailed discussion of feedstock availability.

[16] The term "waste wood," while used here for convenience, is something of a misnomer. So-called waste wood, which once may have had little or no value, is actually a valuable commodity that serves several markets, including the mulch and pressboard markets, as well as the biomass market. As an example of this, sawdust now commands a price of about $40 per ton in New York State.

recycling centers. This wood is sorted and processed in a series of steps to remove metals and other contaminants; however, care should be taken to make sure that such fuels are eligible under programs, such as the New York State Renewable Portfolio Standard (RPS), that distinguish between adulterated and clean wood fuels.[17] Wood content in C&D debris can range from 15% to 85% by weight. The actual amount depends on the source and the methods of measurement. Wood from C&D sources may contain both untreated and treated wood residues, as well as non-wood materials commingled with the wood. The average moisture content of C&D wood is about 12% to 15%.

Most urban wood residues, even if source-separated by a recycling center or wood broker, are likely to contain some level of contamination, which can cause emissions and waste-disposal problems. For example, municipal solid waste (MSW) typically includes paper, plastic, metal, glass, food, garden clippings, etc. C&D debris can contain metals, oils, chemicals, plastics, glass, and other building materials. Recycled urban waste wood is generally similar to hog wood fuel in quality, and may not be suitable for use in some types of combustion systems.

Urban silvicultural products may also be available. This wood generally comes from tree trimming along highways and power lines, and other urban forest maintenance; it is higher quality than C&D waste and is considered to be unadulterated (see NYS RPS Biomass Guidebook).

Industrial mills are also an important source of wood residues. Since forestry processing residues from primary (e.g., pulp, paper, lumber) or secondary (e.g., furniture, composite boards, wooden handles) manufacturing operations have distinct differences, they are appropriately classified as either primary or secondary mill residues. Primary mill residues, produced by lumber mills and pulp and veneer plants, typically have a moisture content that is greater than 20%. Secondary mill residues, also called dry mill residues, are produced by facilities using kiln-dried wood to manufacture consumer and industrial goods. They are generally characterized by their relatively low moisture content, cleanliness, freedom from bark, and relatively high energy value. Secondary mill residues may be in the form of sawdust, trimmings, shavings, wood flour, flawed dimension lumber, end cuts, chip rejects, sander dust, and other forms, all with varying physical and chemical characteristics. These industrial facilities may sell their waste wood directly to a biomass facility if they do not choose to combust it themselves. However, securing long-term contracts for wood from such sources may be difficult.

Increasingly, "waste" products, especially biomass, are becoming high-demand products that provide a revenue stream to their producers. As woody biomass becomes more in demand, and feedstock supply chains become better developed, producers of waste biomass products will find they have more and better opportunities to sell their products in a competitive market. For the biomass purchaser, it may become easier to source waste biomass products, and these products may be increasingly available as pre-processed, standardized fuels.

Forestry Products

In most areas of the state, the available wood feedstocks are likely to be forest products purchased from a wood broker. This usually means low-grade wood harvested by loggers as a side-product. After selling their higher-value saw-logs and veneer-logs, loggers may sell their low-grade wood—including tree tops and less-desirable types of trees—to wood brokers. Often, the wood will first go to a chip mill, and then to the broker, who can provide it to biomass facilities in a pre-sized form. Brokers offer various grades of chipped wood, including pulpwood (clean wood chips), which is the most expensive variety; bole chips (wood with bark), a medium-grade feedstock; and whole tree chips[18] (whole trees fed into a grinder), which is the cheapest. All wood grades will not be appropriate for all biomass facilities; for example, large, high temperature direct combustion facilities can generally use the cheapest feedstocks, while smaller facilities

[17] Some waste wood from urban sources is considered "adulterated" (contaminated) and may not qualify as a renewable fuel under the NYS RPS unless a primary fuel conversion step, such as natural biological processes, gasification, or pyrolysis, is employed to create a clean gas or liquid fuel prior to combustion. For more information, see the RPS Biomass Guidebook, available online at http://www.nyserda.org/rps/RPS_Biomass_Guide.pdf.

[18] Whole tree chips are also known as "hog fuel," "virgin wood," or "dirty" chips.

may need clean chips to avoid maintenance problems (for example, the bark in bole chips can carry dirt that, when melted, can siliconize equipment). The moisture content of New York State forestry products also varies, ranging from 40% to 60%. On the whole, forestry products will be more expensive than waste wood fuels, but cheaper than fuels from dedicated woody crops. For reports on current price ranges, consult the NYSDEC Forest Products Utilization and Marketing (FPU&M) program website, at www.dec.ny.gov/lands/4963.html.

In many areas of the state, low-grade forestry wood is underused. Where markets do not yet exist for this type of wood, it is often left behind when loggers take out higher value trees. Some experts estimate that New York's forests are growing three times as fast as they are being harvested; one rough estimate is that loggers could theoretically harvest 9-12 million green tons annually in New York State, while remaining within the parameters of sustainability (meaning the ratio of growth to harvesting would be 1:1). However, it is important to realize that such estimates provide little information about how much woody biomass will actually be available to a particular facility at a given time and in a given price range. While larger facilities may have one or more purchasing managers on staff to secure feedstocks, smaller, less-well capitalized facilities will probably have to rely on wood brokers to provide them a steady supply of fuel. Because the price of delivered, pre-processed wood fuels varies with the distance the fuel has travelled, it is important to include delivery charges when calculating fuel costs.

Dedicated wood energy crops

Dedicated wood energy crops, such as willow and poplar, are not as cheap as waste wood or ubiquitous as low-grade forestry products; but if a nearby source can be found, they are likely to be cleaner, of more consistent quality, and more reliably produced. The majority of the work done to date in NYS on short-rotation woody crops has been conducted by the Woody Biomass Program at SUNY-ESF. Information and publications from this program can be accessed from the program website, at http://www.esf.edu/willow/.

Research suggests there is little or no agricultural wood available for biomass in New York outside of the SUNY program. This is likely to remain the case unless the cost of growing dedicated woody energy crops drops significantly. A good introduction to willow biomass is Keoleian and Volk (2005).

4.1.2 Grasses

At this writing, there are some grass-pelletizing operations in New York State, but this fuel is not yet available in quantities sufficient for industrial-scale applications (although there are test plots of dedicated grassy energy crops, and experimental grass burns have been conducted at some power stations). Grasses include dedicated crops, such as switchgrass and other perennial grasses; and "waste products," such as low-quality hay. Again, "waste products" is a dated term, as this "mulch hay" may be sold for livestock bedding, ground cover and other existing uses. However, some studies suggest that significant quantities of mulch hay are, at present, unused; this is a resource that could someday be tapped for energy production, if supply chains to service this market become developed.

Although it is drier than green woods such as willow, grassy fuels can create some maintenance issues in boilers. Grass creates more handling problems and is higher in alkali and chlorine content than wood. Biomass fuels with high alkali (principally potassium) or chlorine content can lead to unmanageable ash deposition problems on heat exchange and ash-handling surfaces, and chlorine in combustion gases can cause accelerated corrosion of combustion and flue gas clean-up components. These issues can be addressed through feedstock pre-processing or by installing combustion technologies specifically developed to handle grassy feedstocks. If grass is to be used, it is important to know ahead of time whether system components are designed for grass combustion. The use of non-specified feedstocks can sometimes void equipment warranties.

4.1.3 Other Biomass Feedstocks

There are many potential biomass feedstocks other than woods and grasses. These include manure, food processing waste, and crop residues such as corn stover. As with grasses, the supply chains to provide these feedstocks to biomass direct-combustion facilities are not well developed, competing markets exist, and more research is needed to make them viable on a commercial basis. Some, such as manure and food processing waste, are not well suited for use in direct combustion systems, due to their high moisture content and the likelihood that contaminants are present. These fuels may be more appropriate for use in an agricultural digester or gasifier. Corn stover may be more appropriate as a direct-combustion feedstock, but much of the current supply is used for silage and farm soil maintenance; since New York is a corn-importing state, there is little stover available for off-farm uses. For more discussion of biomass feedstock availability in New York State, see Appendix 2.

4.2 New York State Resources

There is an estimated 400 million dry tons of biomass available for fuel in the United States, but only a small fraction of this biomass can be obtained at a market-clearing price of less than about $20-$25 per dry ton. With the fifth highest state-level potential for low-cost biomass feedstocks in the U.S., New York is well-poised to support growth in biomass technologies.[19]

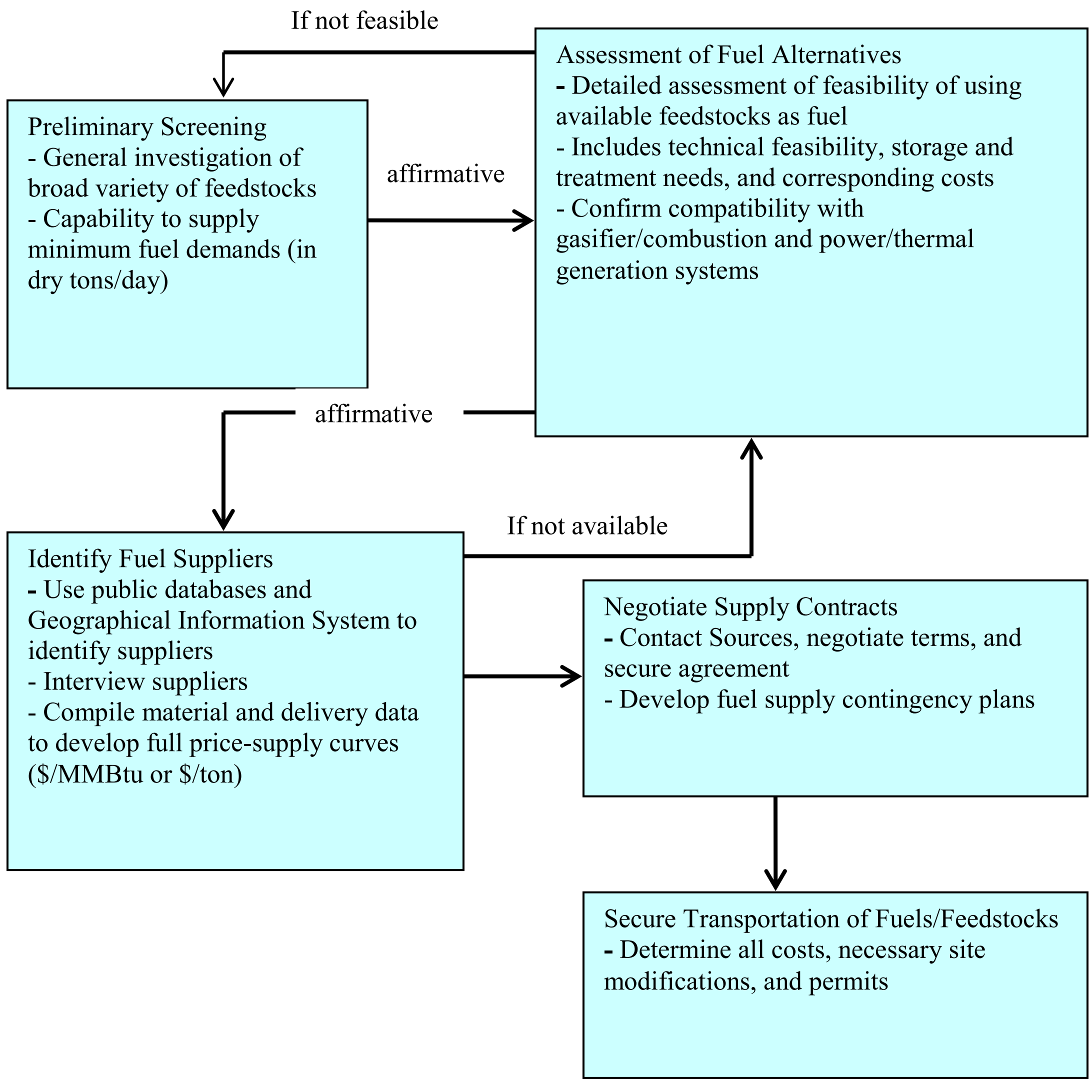
4.2.1 Resource Assessment

The market for feedstocks is fragmented. There is a large diversity of potential sources, but they may be geographically dispersed, limited in quantity, and not able to offer a continuous supply. Feedstock purchasing costs, transportation costs, and moisture content/drying costs can all have a significant influence on project economic feasibility. Providing a source of biomass fuel is not an exact science. However, a well-reasoned approach for any specific project is achievable if several key steps to the process are followed.

Many different factors must be considered when determining which fuel to use in a biomass project. The general process of evaluating the available resources is shown in Figure 7.

[19] Energy Efficiency and Renewable Energy Resource Development Potential in New York State Final Report: Volume Four: Renewable Supply Technical Report. NYSERDA. August 2003.

Figure 7. The Process of Determining Which Fuel to Use in a Biomass Project.



Important characteristics to consider are availability and location of sources, cost, material consistency, and technical compatibility with key equipment in the plant design. A developer needs to perform an analysis of available resources, assessments of technical viability with key equipment (e.g., gasifier/combustion system and power island[20]), impacts on equipment performance, availability, and desired operating schedules, confirmation of reasonable proximity to the project site, and a determination of costs to transport feedstocks to the site (including potential revenues from tipping fees).

Municipal solid waste is readily available in most regions. It is estimated that an average American produces about a ton of solid waste per year, so in regions of reasonable population density finding enough waste to fuel a boiler shouldn't be an issue. MSW is also frequently a low cost option because alternate disposal methods, such as landfills, may require tipping fees. It may even be possible for a biomass project to charge tipping fees for MSW, so long as these fees are lower than those charged by local landfills or waste haulers.

[20] The power producing subsystem of a plant.

However, although MSW may be abundantly available for relatively low cost, it often requires significant, potentially costly, treatment to meet environmental protection requirements for combustion facilities. Use of MSW, as well as construction and demolition (C&D) materials, requires biomass materials to be adequately sorted and separated from other materials. MSW also varies widely in material and energy content. Equipment may need to be modified or the MSW may need to be treated before it can be used as a fuel. This can add significant complexity and costs to project design. In addition, the inclusion of MSW as a proposed project feedstock may trigger strong local opposition from area residents fearful of toxic air emissions and increased waste transport through populated areas. For more discussion of MSW use, see Sections 4.2.3, Notable Considerations and Potential Pitfalls to Avoid, and 4.2.4, Feedstock Transportation and Handling, below.

Woody biomass can be obtained from a variety of sources, including waste from wood mills, forest thinnings, forest residues left over from logging, and urban wood residues from construction and yard trimmings. Availability varies greatly from region to region, so some research must be done to determine if there is a large enough supply within a reasonable distance from the gasification site. Unlike municipal solid waste, there is a competitive market for these products, so a fee per ton must be paid. In the case of thinnings and forest residues, gathering costs can also be a problem. Unlike municipal solid waste, woody biomass is consistent and does not need to be sorted and treated before being used as a fuel.

Other opportunity fuels may be available at different locations. Depending on the feedstock flexibility of the biomass project, these fuels may include construction and demolition waste, animal manure, corn stover, and any other readily available biomass. Analysis of the viability of these fuels must be done on a case by case basis.

4.2.2 Feedstock Flexibility

Feedstock flexibility refers to the ability of a biomass facility to accept various types and grades of fuel. This ability is extremely important because biomass supply chains are not well-established in many areas of the state; because biomass tends to be seasonal in nature; and because competing markets for biomass are emerging. In addition, due to fluctuations in fuel prices, markets, weather and other variables, biomass feedstocks that are available and affordable when a project is being planned may not remain so in the future. Due to real and perceived uncertainties in biomass supply, project financiers may want to see evidence of feedstock flexibility, as well as established supply contracts, before agreeing to finance a project. Many projects have failed to find financing due to feedstock supply problems. In general, equipment should be designed to accept biomass fuels within as wide a range of parameters and specifications as possible, given technical and financial limits and the expected variation in fuel specifications in the region. Long-term fuel supply contracts should be in place when seeking project financing (see financing section).

For reasons similar to those discussed above, it is not advisable to plan a project based on the proximity of a single fuel supplier. Building a biomass combustion facility next to a sawmill may seem ideal, but if the sawmill goes out of business or finds another, higher-value market for its waste streams, the biomass consumer can be left in the difficult position of having to import more expensive wood fuel from a greater distance.

4.2.3 Notable Considerations and Potential Pitfalls to Avoid

Developers need to confirm the eligibility of fuel with respect to the state Renewable Portfolio Standard (RPS), federal tax incentives, and possible relevancy under emissions trading programs.

Air emissions will be a concern for agencies approving the project, politicians, and the general public. There are numerous studies of biomass emissions, both on a point source and life cycle basis (see Appendix 1: Environmental Compliance). Although life cycle emissions profiles are more relevant from a global warming perspective, area residents and agencies are likely to be more concerned about point source emissions. Developers should address this issue early, and necessary emissions control equipment should be included in the project's financial analyses. Disposal of solid and liquid waste should also be considered, both from a permitting and a cost perspective.

Cost, transportation convenience, availability, energy content and material consistency all factor into the decision of what fuel to use at a biomass gasification site. Often, multiple fuels can be used if there is not a large enough supply of a single fuel. This point relates to the previous one made with respect to the RPS. NYS RPS recognizes adulterated biomass fuels. Adulterated biomass feedstocks are materials derived from woody or herbaceous biomass where a treatment or coating has been applied, introducing non-biomass materials; and animal byproducts and wastes. Feedstocks in this category include landfill biomass, animal manures, source-separated waste wood, and biomass from mixed waste. To qualify under the RPS, these feedstocks must undergo primary fuel conversion to biogas or biofuels before undergoing energy conversion. In addition, the facility must be able to demonstrate that the emissions from the adulterated biomass are less than or equal to the emissions from the same plant using unadulterated biomass. For more information, see the NYS RPS Biomass Guidebook, available online at http://www.nyserda.org/rps/RPS_Biomass_Guide.pdf.

Potential biomass projects need to assess which suppliers of biomass lie within a reasonable transportation radius. Though there may be plenty of biomass in an area, wood residues often already have markets, and some are tied up in long term contracts. For gasifiers, it is easier to get waste from landfills, which may be willing to pay to have waste removed. To keep transportation costs reasonable, the source of biomass should be within a 30-50 mile radius of the gasification site. Potential suppliers slightly outside the radius should still be considered when necessary.

If there are several available fuel sources in the area, an analysis must be made of the quality of each option. A very solid understanding of the moisture content of the feedstock resource is critical. Moisture content is important because it drives up the costs of fuel transportation, storage and drying, and penalizes the overall system energy efficiency. MSW is less consistent than wood and must be pre-treated in order to be used as a fuel, but neither wood nor MSW is likely to have the ideal moisture content for gasification. For direct combustion or co-firing, the allowable moisture level depends on the type of combustion system being used, but drier fuels are always better, though generally more expensive to purchase. Drying, therefore, is a common first step in the gasification or combustion process.

4.2.4 Feedstock Transportation and Handling

4.2.4.1 Transportation

Biomass feedstock transportation costs are site specific and depend on the distance from the plant as well as the amount of biomass to be transported. In general, biomass feedstocks suffer from low energy density and high moisture content, making them uneconomical for transport over large distances. However, each potential feedstock has specific transportation issues. Project developers need to determine all transportation related costs. In addition to cost attributable to fuel on a delivered ton basis, this may include capital costs for necessary site modifications and permits.

Developers typically use public databases (e.g., U.S. Forest Service Timber Products Output database and State regulatory agencies) and Geographical Information Systems (GIS) to identify suppliers within a set of predetermined radii (e.g., 20 miles, 30 miles, and 50 miles) of the proposed plant. Potential suppliers are then contacted and specific data is requested with regard to both material and delivery costs. Transportation costs are included in comprehensive price-supply curves generated for all suppliers.

For wood feedstocks, at this writing, transportation costs typically fall between $8 and $15/ton materials within a typical 30 mile radius, for forest residues (trees or other types of vegetation), industrial mill residues, and urban wood residues (C&D).

In the case of Municipal Solid Waste, estimates of waste production are based on assumptions for waste generated per person in the surrounding area and the corresponding population. Considered in the population estimate needed to support a biomass facility is the distance to be traveled to move material to the facility. For gasifiers, 30 miles maximum transport distance is a good general rule; for direct combustion and co-fire facilities, 50 miles is often used. The cost to transport will change with the weight of the fuel (related to moisture content), density of vehicular traffic, population distribution, types of roadways within the area, vehicles employed, labor costs, energy costs, and even weather patterns. The majority of MSW is disposed of at landfills, costing the supplier a tipping fee ranging from around $40 to $60 per ton. A biomass project could charge a $20 to $30 per ton tipping fee.

Once all local resources are assessed with respect to potential (dry tons/year), supply costs ($/tons) and transportation costs ($/ton, factoring in any tipping fees), the total delivered costs ($/ton) can be calculated.[21]

4.2.4.2 On-Site Handling

Moving fuel from the point of delivery, or from long-term storage areas to short-term storage areas or the combustion area, can be accomplished using some combination of wheel loaders, crane systems (these can be automated), belt or chain conveyers, screw conveyers, hydraulic piston feeders, bucket elevators and pneumatic conveyors. For smaller particle sizes stored in silos, discharge can be accomplished using a rotating or inclined screw with agitator. Conveyance of fuel from short-term storage to the combustion chamber can be accomplished by various means, including sliding bar conveyors and walking floors (Van Loo, *et al,* 2008).

Different types of biomass require different types of handling (for example, some types of fuel handling systems are better for fuels that produce a lot of dust). Table 8 matches fuel characteristics with feeding and handling systems and combustion technologies (Van Loo, *et al,* 2008).

Table 8. Fuel Characteristics According to Feeding and Handling System and Combustion Technology. Source: Backman, et al, 1987, as used in Loo, et al, 2008.

Shape	Maximum particle size	Appropriate delivery system	Appropriate combustion technology
Bulk material	<5mm	Direct injection, pneumatic conveyors	Directly fired furnaces, cyclone burners, CFB
Bulk material	<50mm	Screw conveyors, belt conveyors	Underfeed stokers, grate furnaces, BFB, CFB
Bulk material	<100mm	Vibro-conveyors, chain trough conveyors, hydraulic piston feeders	Grate furnace, BFB
Bulk material	<500mm	Sliding bar conveyors, chain trough conveyors	Grate furnace, BFB
Shredded or cut bales	<50mm	Cutters/shredders followed by pneumatic conveyors, screw conveyors or belt conveyors.	Directly fired furnaces, grate furnaces, BFB, CFB
Bales, sliced bales	Whole bales	Cranes, hydraulic piston feeders	Grate furnaces, cigar burners
Pellets	<30mm	Screw conveyors, belt conveyors	Underfeed stokers, grate furnaces, BFB, CFB
Briquettes	<120mm	Sliding bar conveyors, chain trough conveyors	Grate furnaces, BFB

Another piece of fuel-handling equipment that may be needed is a truck dumper for unloading fuel at the point of delivery. This is an hydraulic system that can lift and tilt an entire truck or trailer, emptying it within minutes. Generally, facilities without a truck dumper will be obliged to purchase more expensive

[21] Estimates for loading, transport, and processing can be calculated using publicly available tools such as the *Forest Residue Transportation Costing Model* (FoRTS) from the US Forest Service Forest Operations Research Unit.

fuel from a supplier that uses dump trucks. Since a truck dumper can cost around $500,000, this decision represents a tradeoff between up-front investment and long-term operating costs.

4.2.5 On-Site Fuel Processing: Gasification

4.2.5.1 Feedstock Receiving and Storage

With the exception of feedstocks generated onsite (e.g., mill waste), virtually all biomass is delivered by truck to industrial and large commercial users. Receiving, preparation, and storage requirements will depend on the size of the project and feedstocks used. Typical requirements include equipment required to process the biomass to make it suitable for use in the energy conversion device.

Receiving systems are part of all biomass systems and not unique to gasification projects. However, biomass gasification systems are in the intermediate to larger size range of biomass projects, meaning they require large fuel volumes. As biomass power projects increase in size, economies of scale are partially offset by increased transportation costs associated with hauling biomass feedstocks farther distances.

Listed below are some types of fuel receiving and handling equipment that might be suitable for facilities requiring different amounts of fuel.

50-100 tons/day: A light-duty frame-tilt hydraulic dumper might be used for unloading fuel. For these systems, the trailer must first be disconnected from the tractor. Front-end loaders or bulldozers move the fuel from the concrete pad and stack the biomass on the storage pile. A system sized for 100 tons/day would handle about four to five trucks per day.

>100 tons/day: this size facility typically uses standard semi-trailers and hydraulic dumpers that can lift and tilt the whole truck up to an angle of 75°. The system includes a live-bottom receiving hopper. From the concrete pad, the fuel is conveyed to a woodpile. An automated storage radial stacker is used to stack the fuel on the pile for future processing needs. A system sized for 400 tons/day capacity would handle about 20 trucks per day.

Fuel preparation equipment includes but is not limited to:

- Separators
- Manual separation/inspection cabin
- Sorting belts
- Grinders
- Screens
- Transfer conveyors
- Dryers
- Fuel metering

As is the case with all biomass projects a sufficient amount of fuel needs to be stored onsite. Storage and gasification system equipment would include:

- Fuel storage silos
- Gasifier feed system
- Gasification reactor
- Cyclone separator systems
- Combustion reactor
- Gas conditioning reactor

- Startup system
- Ash handling system
- Flue gas and product gas heat recovery system

The primary purpose of storage is to retain the biomass in suitable condition in a convenient location for it to be transferred to the next stage of processing, combustion or energy conversion. In sizing storage capability, the objective is to manage deliveries of feedstocks in a manner that minimizes onsite storage and management while still maintaining a sufficient reserve. Being able to minimize onsite storage of biomass has significant implications for project siting. Meeting this goal is essential to minimizing plant siting and permitting risks. The type of storage system used at the production site, intermediate site, or plant can greatly affect project costs as well as quality of fuel.

4.2.5.2 Feedstock Processing

Common steps in feedstock processing include separation, sizing, removal of metals and other noncombustible materials, and grinding or other size reduction methods. Particle size control (size reduction or pelletization) is important in gasifier performance, in particular for fluidized bed systems. Much feedstock processing is commonly accomplished by the feedstock supplier, but increases the price of the feedstocks; it can also be done on-site.

In gasification projects, biomass must also be dried if moisture content is high. The amount of moisture that can be tolerated depends on the type of gasifier (for example, fluidized bed gasifiers have a higher tolerance for moisture than fixed bed systems). Fuels can be dried using drying equipment or by storing it in large piles during dry weather. These approaches will enhance the value of the material's fuel value and may not increase operational costs significantly. However, the economics and other factors specific to individual sites will determine whether drying facilities make economic sense.

4.2.5.3 Pre-Gasification Treatment

Because gasification processes typically require fairly dry fuels for proper process function and control, feedstock drying is an integral part of most gasification designs.

Green biomass, defined as freshly harvested plant material, is the most readily available and inexpensive biomass product, but it can contain a significant amount of water by weight (up to 60%). This water does not contribute to the energy content of the syngas, but does consume a significant amount of energy in gasification. Even though water cannot be burned (oxidized) at elevated temperatures, it will dissociate into its elemental components—hydrogen and oxygen. The hydrogen will contribute to the calorific value of the syngas. This reaction is very temperature-sensitive, and the hydrogen and oxygen will usually recombine into water vapor as the syngas cools. Therefore, the moisture content of biomass must be strictly limited. If there is excess moisture, the gasification process cannot sustain itself without an additional external source of heat to reduce the moisture. Excessive moisture increases costs due to drying and decreases energy efficiency. As the moisture content of the biomass increases, the net energy available in the syngas decreases. Fixed bed gasifiers that use internal combustion of the syngas typically require biomass with less than 20% moisture content. Fluidized bed gasifiers typically require biomass with less than 30% moisture content. The drying process requires a considerable additional capital investment and increases the O&M costs. Unfortunately, the cost of the drying equipment (equipment cost and O&M cost) seldom covers the cost savings of using green biomass.

As syngas leaves the gasifier, it contains several types of contaminants that are harmful to downstream equipment, ash handling, and emissions. The primary contaminants in syngas are tars, particles, alkali compounds, and ammonia. The specific types of contaminants observed will depend on the biomass feedstock and the gasification process used. The degree of gas cleanup must be appropriately matched to its intended use. Reciprocating engines, gas turbines, and especially fuel cells require a very clean gas.

Because gasification occurs at an elevated temperature, syngas can have as much as a third of its total energy in sensible heat. Cleaning the gas while it is hot would be advantageous from an energy use perspective, but this task is currently difficult to accomplish. Research is ongoing regarding hot gas filters, which can be applied in coal gasification, as well as other high-temperature processes. Wet scrubbers are currently one of the most reliable and least expensive options for gas cleanup, even though they sacrifice a large portion of the sensible heat of the syngas. On the other hand, cooling the hot syngas can provide a source of steam for the cleaning process, power generation, or end-use.

4.2.6 On-Site Fuel Processing: Direct Combustion and Co-Firing

4.2.6.1 Fuel Drying and Storage

On-Site Fuel Drying

Fresh wood fuel can have a relatively high moisture content, and this has a great impact on the energy content of the fuel and the efficiency of combustion. Typically, the moisture content of fresh wood is greater than 50wt% (w.b.[22]); by comparison, the moisture content of waste wood or straw is generally less than 15wt% (w.b.). In New York, delivered "green" wood chips will vary in moisture content from the low 40% range to the mid 50% range over the course of a year; the price is generally based on an average moisture level, and smaller combustion facilities don't usually measure moisture content on a delivery-by-delivery basis (Benson, 2009).

Most biomass-fired plants in New York use green wood chips. This is especially true of the larger grate-type combustion systems, which use heat from firing to drive off excess moisture from the fuel as it approaches the combustion area. Smaller biomass-fired plants, and those that operate at lower temperatures, may require drier fuel. Drying biomass fuel is one of the best ways to improve the thermal efficiency of combustion; for example, drying from a moisture content of 50wt% to 30wt% (w.b.) can provide an 8.7% improvement in potential thermal efficiency (Van Loo, 2008). It is possible to purchase pre-dried fuel[23] or, if space is available on-site, it is possible to dry fuel after purchasing it. However, either option will add significantly to fuel costs.
In addition to the level of moisture in the fuel, the constancy of moisture levels is also important. Generally, combustion is optimized when the moisture content of the fuel is as constant as possible, allowing the combustion system to operate at a steady state. Following dry fuel with wet, and vice versa, requires more complex combustion technologies and process controls to maintain combustion at optimum efficiency. If the moisture content of delivered fuel is highly variable, one way to achieve a more constant moisture level is to store some relatively dry fuel on-site to use as a blend stock. Varying the blend ratio of stored to newly-delivered fuel can help maintain a more constant moisture level in the combusted (blended) fuel. If no fuel is stored on-site, the system operator must make adjustments to accommodate the moisture level of the delivered fuel, however wet or dry it may be.

[22] Moisture content can be described on a wet basis (w.b.) or a dry basis (d.b.). These are simply two different ways of calculating moisture content. *Moisture content w,* on a wet basis, is defined as the mass of the water content divided by the mass of the water content plus the mass of the biofuel d.b., multiplied by 100%. *Moisture content u,* on a dry basis, is defined as the mass of the water content divided by the mass of the biofuel d.b., multiplied by 100%. Since these two methods are very different, it is important to know whether moisture content is being calculated on a wet or dry basis (Van Loo, et al, 2008).

[23] It is also possible to purchase wood pellets. While they are generally viewed as a fuel for residential-scale applications, some industrial- or institutional-scale biomass combustion facilities may elect to use wood pellets due to site-specific limitations, such as restrictions on truck traffic or a limited amount of storage space. This is a trade-off, as pellets are a more processed product and therefore more expensive than wood chips. Note that there are different grades of wood pellets available; an industrial scale facility may be able to use cheaper pellets with higher ash content than would be desirable for residential applications.

The simplest way to dry biomass on-site is to store it in a pile. Due to biological processes, the temperature in the pile will increase, creating a convection effect that circulates air through the pile. This often results in drying at the center of the pile, while the upper area of the pile can remain moist due to convection (and, in the case of outdoor storage, rain). The main drawbacks to this method are that it requires a lot of space and time and, for outdoor storage, weather is a factor. In addition, biological degradation can result in dry-matter losses and fungal growth.

Generally, an average pile storage time of about a month is optimal; this allows the fuel to dry but minimizes degradation of the wood, which decreases its energy value. However, this is only a guideline. Actual pile storage times will vary depending on a number of variables, such as moisture content at delivery, desired moisture content at combustion, ambient air temperature and humidity, etc. Particle size will also be a factor; recent studies have shown that the length of woodchips stored in a pile impacts temperature, drying, mold formation, mass and energy loss. A minimum average length of 100mm is recommended to minimize energy losses and mold formation (Van Loo, et al, 2008).

Frequently, the time of residence in storage piles will also be limited by space considerations. Because most small-scale biomass combustion facilities have limited on-site space for fuel storage, fuel residence time tends to be brief. Under these conditions, outdoor pile drying presents some uncertainty, since it is impossible to predict to what degree moisture will be reduced over a brief span of time. Drying in winter is likely to be less successful than drying in summer, especially for outdoor and unheated facilities.

Pile drying can be improved by ventilating the pile with ambient or warmed air. This is usually only economically feasible if a free or inexpensive heat source is available, such as from an active or passive solar system, or from a process waste heat source such as flue gas. Some facilities have tried drying biomass fuel in grain drying bins or sheds, or in silos with forced air ventilation.

In general, the decision of whether to dry wood fuel on-site will involve a calculation of the economic benefits and costs of doing so, but may also depend on the type of combustion system in use and the availability of storage space near the facility.

On-Site Fuel Storage

Ideally, a biomass combustion facility will have both long- and short-term fuel storage areas. Even if just-in-time fuel delivery is planned, a small amount of fuel in long-term storage on-site can help to avoid unscheduled down time in the event that fuel deliveries are delayed, and allow for fuel mixing to achieve optimal moisture levels, as described above. A short-term storage area, with automatic feeder system, will also be needed to feed fuel to the combustion chamber.

Storage in piles is generally the simplest method, but care should be taken to avoid a number of potential negative side effects of pile storage:

- **Self-heating.** Self-heating, which can lead to self-ignition, can occur if the pile is compacted, or if the pile is not homogenous (contains different materials, or different batches of the same material, with different moisture content). Temperature and gas (CO_2 and CO) measurements taken at various points on the pile can provide early detection of self-heating. For further protection against the possibility of self-ignition, limit pile heights to 8m and storage time to five months. Natural convection of air through the pile is also helpful in avoiding self-ignition and for drying (for this purpose, larger particle sizes are preferable).

- **Emissions.** Outdoor pile storage of small particle sizes (sawdust) can cause dust emissions, a problem in populated areas.

- **Moisture and Leaching.** Outdoor storage poses the risk of increases in fuel moisture content due to rain. Leaching from rain can also result in waste water control and treatment issues. Baled wood can generally be stored outdoors with less risk, as it does not tend to degrade quickly and is not as sensitive to moisture.

- **Mineral Contamination.** Pile storage on the ground can cause mineral contamination of biomass from sand, dirt and stones; this in turn can cause maintenance problems in combustion equipment. Storage on paved surfaces will significantly reduce this problem.

CHAPTER 5 – AGRICULTURAL DIGESTERS

5.1 INTRODUCTION

Biogas, a flammable gas containing methane, can be produced from agriculture and food processing waste products using anaerobic digester technology.[24] Anaerobic digesters optimize the environment for naturally occurring anaerobic bacteria to accelerate decomposition of the feedstock. The most common feedstock is manure from dairy cows, poultry, or hogs. Recently, large anaerobic digester facilities have increasingly been designed to use food processing wastes, sometimes to supplement manure feedstocks.[25]

The biogas produced by the digester may be used onsite as a heating fuel and to generate electricity. In most cases, electricity is produced using an internal combustion engine or a small gas turbine engine. It is also possible to process the biogas for introduction into natural gas pipelines, although this is not yet being done in New York.

In addition to biogas, anaerobic digestion produces a number of useful byproducts, including crop fertilizer, livestock bedding, and aquaculture feed supplements. These products can provide revenues or farm cost savings to offset system costs. Additional revenues can be generated from the sale of carbon credits and other emission credits.

A typical digester system process includes the following main components:

- Feedstock collection
- Anaerobic digester system
- Post-digestive treatment
- Effluent storage
- Biogas handling
- Biogas use

There are four common types of digester technology:

1. Plug-flow – historically the most commonly used in the northeastern U.S.
2. Covered lagoon – better suited to warmer climates
3. Complete mix – the most prevalent design in Europe, designed to combine (mix) manure and other organic waste streams to maximize biogas production; and
4. Fixed film – a relatively new technology better suited to feedstocks with a very high liquid, low solid content.

Most of the farm-based anaerobic digesters in New York are plug-flow or modified plug-flow digesters. A plug-flow system usually includes a below-grade concrete containment pit, with a cover to capture the biogas. The plug-flow approach is somewhat similar to a septic tank system, in that material entering the containment vessel is pushed through by material that comes after it, travelling together with neighboring material in a plug. Modified plug-flow digesters usually differ only in that they incorporate some type of mixing capability.

[24] Biogas created in agricultural digesters is typically about 60% methane, with the remainder being mostly carbon dioxide and traces of hydrogen sulfide. This should not be confused with wood gas, which results from the gasification of wood or other biomass and is composed primarily of nitrogen, hydrogen, and carbon monoxide, with only trace amounts of methane.

[25] Technically, a digester can process a wide variety of biomass feedstocks including animal manure, slaughterhouse wastes, fish processing wastes, starch, sugar, grains, grain products, and vegetable oils. The use of food processing wastes to maximize biogas production is common in Europe and is beginning to be seen in the U.S., although the dominant application in the United States continues to be manure management at hog and dairy farms.

Although the plug-flow design is currently the most common in New York, complete mix systems are more efficient and will likely gain in prominence as they become more widely understood. Complete mix anaerobic digestion technology is not new; it has been widely applied in the U.S., particularly in the municipal wastewater field, for well over thirty years, and has been used extensively in Europe for the decomposition of organic waste food sources and manures for more than twenty years. The basic technology confines a mixed bacterial community at a specific temperature within a closed vessel (usually a steel or concrete above-ground tank) in the absence of oxygen. A mixer agitates the substrate within the tank, ensuring a "complete mix" of the substrate with the bacteria. The bacteria produces several products, including digester gas.

Historically in New York State, agricultural biomass projects have been based either on aerobic composting of organic biomass material, or anaerobic digestion in a fixed containment vessel. In general, farm-based anaerobic digestion is not widely practiced in the United States. As of February 2009, the United States Environmental Protection Agency, under the AgSTAR program (USEPA-AgSTAR), estimated that there were 125 farm-scale digesters operating at commercial livestock farms in the U.S. As of August, 2009, in New York, there were 12 operating farm-based anaerobic digesters, with another 12 under construction, nine in planning stages, and six decommissioned (Pronto, 2009).

There are three predominant temperature ranges in which anaerobic digesters operate. These ranges are classified as psychrophilic (around 80 degrees Fahrenheit), mesophilic (around 100 degrees Fahrenheit) and thermophilic (around 130 degrees Fahrenheit). The mesophilic anaerobic digester temperature range is by far the most common and is the biological process most resistant to upset.

Research data from 2001 indicates that New York State has the third largest dairy cow population in the United States, with 947,000 cows. Since an average 1,500 pound dairy cow produces about 25 gallons of manure per day (solids, urine and parlor waste) which contains about 8.5% total solids, a reasonable estimate of the amount of dairy manure produced in New York State per day would be 19,490,000 pounds or about 98,745 tons (procon.org). Additionally, there are significant quantities of manure from varied other sources including beef cattle, horses, swine and poultry.

The second major organic waste source to consider is the food waste fraction of municipal waste, which can be expected to be between 14-18% of the entire municipal solid waste stream (Gray, 2008). The average American discards 4.4 pounds per day of solid waste (www.recycling.colorado.edu/education). During 2004, according to the New York State Department of Environmental Conservation (NYSDEC), New York residents, institutions, commercial businesses and industries generated 37.2 million tons of solid waste, excluding biosolids (treated sewage sludge) (New York State Department of Environmental Conservation; Solid Waste Management Facilities)[26].

A third major source of organic waste is food processors. A case study published in 2008 estimated that food production waste comprised some 20% of the 10,205 tons of food waste generated annually in a single U.S. county during 1998-1999 (Griffin, et. al., 2008). Although this statistic may not be representative of the average county in New York State, it does give a sense of the potential scale of this organic waste source.

[26] There is some interest at NYSDEC in banning organic materials from landfills. If instituted, this would significantly increase the supply of organics for digesters.

5.2 SYSTEM PARAMETERS

5.2.1 Resource Assessment

Fuel Sources

Organic waste materials that can be used as anaerobic digester feedstocks are widely variable. Significant sources include:

- Manure (Cow, swine, horse and poultry)
- Slaughterhouse waste
- Pre- and post-consumer food waste
- Food processing waste
- Beverage/brewing waste (beer, wine, liquor, etc.)

Information on the location of organic waste materials in New York State is maintained by the Cornell University Department of Biological and Environmental Engineering, and may be found online at http://wastetoenergy.bee.cornell.edu/default.htm. In addition, Cornell Waste Management Institute maintains significant information on organic waste sources previously canvassed for composting facilities throughout the State. This information is available online at http://cwmi.css.cornell.edu/composting.htm.

Much of New York State's food processing wastes, at least with respect to fruits and vegetables, are generated on a seasonal basis. Unless multiple staggered plantings of a particular vegetable are made, a particular harvest period for that vegetable may only be on the order of a few weeks. However, progressive harvesting of various vegetables (peas, beans, carrots, beets, cabbage (white/red), corn, potatoes, tomatoes) generates processing wastes for approximately a six-month period, from June through late October/early November. The grape harvest season typically lasts approximately 5-7 weeks depending on the weather for a given year and the sugar level (brix) for the different grape varieties on the vine.

Despite their seasonality, vegetable and fruit processing waste quantities in the U.S. have historically been greater than the local economies can absorb. This means large amounts are disposed of in whatever manner is least expensive, which oftentimes is landfills. In upstate New York, disposal rates at landfills in early 2009 range from $20 to $25 per ton.

Due to the seasonality and quantity of vegetable and fruit processing waste in New York, provisions must be made for storage and preservation of these wastes if they are to be used as fuel materials on a year-round basis. Storage and preservation could take place at the source of the material or at the anaerobic digester facility itself, and might take the form of silage.

Fuel Composition

Anaerobic digesters operate best when they are fed a uniform and consistent fuel mix. This may not be as simple as it sounds, as similar materials from different sources may be inconsistent due to different source processing techniques. It is also important to carefully monitor the amount of water in the substrate. Materials that have the minimum amount of water are desirable (less water requires less heat in the anaerobic digester) but solids in excess of 9% are hard to pump. Materials that are high in sugars are preferable to materials with high cellulose content. Not only is the gas production better from such materials, but the residence time required for complete digestion is less.

While all the organic waste streams listed above provide potential fuel substrates, their individual gas-producing value is highly variable (Bavarian State Institute for Agriculture). The rate at which different types of organic waste materials digest in an anaerobic digester generally decreases in the following order:

1. Sugars
2. Carbohydrates

3. Fats (oils and greases)
4. Protein
5. Hemicellulose material
6. Cellulose

The preceding is important since the ease with which material is digested affects digester sizing and the rate and quantity of digester gas production.

Note that animal manure alone does not make the best fuel for producing gas in anaerobic digesters, simply because much of the fuel value has been removed within the animal's digestive tract; for this reason, digester efficiency may be greatly increased by adding other feedstocks. However, manure still offers significant digester gas production potential, as it is available in significant quantities, it provides a medium for bacteria colonization and it provides the bacteria. Most importantly, it provides a pH buffer for other wastes. These benefits, combined with manure's availability and low cost, and the farm management benefits of processing manure in a digester system, make the development of digester systems on or near manure-producing farms a common and effective application of this technology.

While the debt service for an anaerobic digester can typically be in the 7-10 year range, individual feedstock suppliers will likely not contract to supply fuels over such a long period. Therefore, the developer will have to remain alert to new fuel sources that have gas-producing potential consistent with the original digester design. The ability to obtain organic waste sources, the distance they are from the anaerobic digester facility, the quantity/quality of the materials, the need/cost of on-site storage and the potential for charging a tipping fee will all determine the value of any given feedstock source to a project.

Substrate Sample Testing

Independent of what feedstocks are being considered for anaerobic digestion, the best way to evaluate their gas production potential is by having representative samples tested by a laboratory. For assessing basic gas production potential the following tests should be performed:

- % solids
- % volatile solids
- Biochemical methane production potential (BMP)
- Carbon content

The BMP test can take about three months to complete, and costs approximately \$250 - \$275. This price is not inclusive of other per sample costs for labor, materials, shipping, etc. The remaining tests can be performed for a per sample price of under \$100 each.

Laboratories can also test the levels of ammonia, total nitrogen and phosphorus in the feedstocks. This will help in predicting whether certain characteristics of the substrate may inhibit the digestion process.

Plugging the lab data into the conversion efficiencies provided by the CHP manufacturer, it is possible, using the predicted biogas output, to calculate the heat and power potential of the system. This will form the basis for offtake contracts that directly affect the project's revenue stream. More importantly, lab data offers a third party evaluation of the design parameters of the system, which can help support an investment or lending decision.

Fuel Transportation

Transportation of organic substrates will generally be by truck, and will generally consist of dead end hauling, i.e., a trailer is full only one way and returns home empty. This situation tends to lead to higher costs, and the use of more regional haulers who specialize in this type of service. The possibility does exist that organic waste materials are presently being disposed of in other locations at farther distances; if this is the case, a new digester project may offer a more cost effective alternative in closer proximity to the source of the materials.

The type of truck necessary to transport waste materials will be decided by the characteristics of the materials. Appropriate transport trailers might include tankers, sealed roll-offs, and bulk carriers for some dryer types of food waste, such as grape pomace. For materials high in water content, watertight trailers will be needed. Box trailers would likely not be appropriate, since they are used for hauling packaged materials, and are not easily cleaned.

The actual costs for hauling organic waste materials are difficult to predict and will be determined by a combination of per mile over the road charges and the following associated factors:

- Equipment required
- Actual mileage travelled
- Applicable fuel surcharge
- Any applicable accessorial charges, ie. tarps, detention, tolls, destination charges
- Special permits

The costs could also vary depending on seasonal availability of the specific required equipment. For example, during harvest season many trucks are required to run produce to the distribution centers.

5.2.1.1 Anaerobic Digestion as a Waste Treatment Alternative

One of the reasons for choosing anaerobic digestion technology, particularly in the agricultural sector, is to better handle large volumes of animal manure. In recent years, as farms have expanded the size of their operations through addition, acquisition and/or consolidation, anaerobic digestion is more often considered as a cost effective manure management strategy. As noted previously, the design of some anaerobic digester systems offers the opportunity to co-mingle organic waste streams in a designed ratio (recipe) that can increase biogas yields while minimizing environmental impacts of the total waste stream.

When considering alternative waste streams, it is important to consider the operational parameters of the equipment as well as the bacteriological processes involved. The primary considerations for evaluating organic waste material to be considered as potential substrate fuel sources are:

- % dry matter
- % volatile matter
- % water
- Gas production potential
- Biological inhibitory agents such as cleaning chemicals, disinfectants, antibiotics
- Foreign contamination such as with plastics, glass and paper
- Temperature

Tables developed by European researchers show anticipated values for % dry matter, % volatile matter, and gas production potential for many organic waste materials (Bavarian State Institute for Agriculture). However, the data has been found to be quite variable even for similar materials. This could be a function of different processing techniques in Europe, or differences in materials, such as apple pomace from different species of apples. It is best, when considering a new source of organic material, to test representative samples for the basic parameters listed above.

5.2.1.2 Key Operational Parameters

A wet mix anaerobic digester (whether plug-flow or complete mix type) is basically a large bacteria community confined within a vessel. Since this bacteria community is a living organism, its environment must be maintained within certain operational limits. Some key operational parameters to consider for best anaerobic digester performance are:

- Mix (agitate) substrates evenly within the digester
- Maintain operational temperatures
- Input material of a consistent, regular size (and not large sizes that are hard to mix)
- Feed in new material on a regular basis
- Gradually introduce new types of food substrates (don't shock the bacteria)
- Continuously monitor process performance parameters, such as methane percentage present in the digester gas

Most mesophilic anaerobic digester systems will not require special fuel treatment, such as blending, thickening and/or temperature adjustment, prior to introduction. However, it is essential to remember that changes to the bacteria's environment will cause process upsets and reduced digester gas production. Maintenance of a stable environment within the digester will produce a stable biogas product in terms of methane content.

European system designers typically offer a remote monitoring package that enables the owner/operator to observe key process variables from any location with an internet connection. This information is an essential part of the proactive management of an anaerobic digester system. In many cases this consists of sensors measuring a number of operations including inlet valves for substrate, temperature and pH levels within the digester vessel, outlet valves, gas pressures, biogas methane content, etc. The data from the sensors is accessed through a modem at the project site. This information is not only useful to the owner, but can be made accessible to manufacturer support teams, to assist in ongoing operations.

Most European manufacturers also include a Supervisory, Control and Acquisition of Data (SCADA) system as part of the standard design. This technology allows the automatic collection of the key process data and enables comparison against other systems without reliance upon human intervention. The SCADA system may be coupled with a Process Logic Controller (PLC), which allows the operational support team to monitor digester performance, interpret data, predict behavior, and make real-time system adjustments to maintain/optimize performance.

Operating Hours

Fully operational anaerobic digesters are designed to run on a continuous basis, 24 hours per day and seven days per week, and CHP units in general are best operated under full load at least 21 hours per day for maximum performance. However, like all equipment-based systems, an anaerobic digester that is fed deleterious (inert and/or indigestible) materials such as rocks, metal objects, plastic, sand, etc., may eventually require cleaning or other maintenance. Indigestible materials may cause deposits to form inside the digester, which over time will lead to diminished operational capacity. Anaerobic digesters are best fed on a regular basis, but can go a few days without being fed; however, in such situations they should be monitored closely to detect early signs of bacterial process distress.

5.2.1.3 Storage Requirements

Manure Storage

Since the majority of anaerobic digesters proposed for New York will likely be located within an agricultural setting, the storage requirements for manure may already be present. Many farms have existing lagoons that historically have been a common means of storing/handling manure. The integration of existing manure handling operations with anaerobic digester feeding operations must be considered. This marriage of needs can often be addressed through pumping and piping modifications between existing manure handling infrastructure and the proposed new digester facilities.

Organic Waste Storage

The greater challenge usually is in handling and, if necessary, storing the supplemental organic food wastes to be blended with the manure as fuel for the anaerobic digester. The need for storage depends in large measure on the nature and sources of materials to be used.

Recent NYSERDA-sponsored research, conducted by NorthEast Biogas, LLC, supports the viability of ensiling seasonally-produced fruit and vegetable wastes so they can be fed into a digester throughout the year at continuous feed rates.[27] These materials could be stored at the source of generation, but more likely would be stored near the digester facility. The materials would be blended with an inoculant and covered, so that spoilage would not damage them. Depending on the material type, there may be some need for mixing/feeding equipment to prepare them prior to introduction into the digester.

Supplemental liquids for introduction into a digester, such as oils and greases from food preparation, may require a mixing tank upstream of the digester. This tank should be insulated and designed with a provision for heating. This would allow for consistent blending of oils with other feed substrates prior to introduction into the digester.

Sizing

When sizing storage facilities, it is important to consider the potential for supply interruptions, for example, road closures due to snow and ice. Storage facilities should be of adequate size to ride through such temporary supply disruption while maintaining a consistent feed-in to the digester.

The sizing of the storage facilities will also be a function of the quantity of material available and the volume a given amount of material consumes, i.e., cabbage waste may require more space then fruit pomace. Storage design consideration should be given to annual required space, access and proper covering (to minimize leachate generation and run-off).

Some materials may require special storage considerations – for example fats, oils and greases that need to stay "liquid" might require a heated storage tank. Other materials might simply need a cover to prevent the ingress of moisture (rain).

Quality Control

Independent of the nature and/or source of supplemental organic wastes, a proper materials receipt program coupled with periodic quality testing is important. A contract to supply organic waste should contain parameters governing the characteristics of the waste, for example the percentage of total solids, and should stipulate that the waste be free of contaminants such as debris, wood, rubber gloves, cleaning agents, etc.

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[27] This material is, at this writing, in preparation; a report will be made available when the project is complete.

Quality testing upon receipt of waste delivery is intended to ensure that each delivery is within the previously agreed tolerances. Inconsistency and/or contamination in supplemental organic wastes can cause digester upsets, diminished or lost digester gas production or in the worst case total digester process failure (i.e. death of the microbial colony, and the cessation of biogas production). It is not uncommon for total digester process failure to take a digester out of service for 60 days. The host facility should also consider an alternative tipping arrangement in the event that organic wastes arrive in a contaminated or otherwise unsuitable condition and cannot be fed into the digester. In such a case, the ability to substitute pre-qualified alternative organic wastes could avoid negative cost and process implications to the digester operator.

5.2.2 Space Requirements

The amount of space required for an anaerobic digester facility is a function of many variables, including:

- What size (volume) of digester(s) is needed to handle the volume of input substrates?
- What is the nature of the input substrates?
- What kind of anaerobic digester process is planned?
- Is on-site post digester solids dewatering planned?
- Will on-site storage of input waste organic substrates be required?
- What is the planned use for the post digested liquids and solids?

The minimum area requirement for a single main anaerobic digester tank with basic supporting peripherals is about one-half to three quarters of an acre. A two tank system with basic supporting peripherals could require 1.5 to 2 acres. However, the variables listed above can significantly influence the space required for a project and the improvements necessary.

Various characteristics of the land can also influence the required acreage. The following are some of the more significant parcel characteristics that can impact space needs:

- Steep slopes
- Wetlands
- Farm layout
- Interconnect set-up (pipe gas or run electrical lines)
- Existing right-of-ways
- Existing access agreements
- Existing utilities
- Existing water bodies
- Local zoning
- Required buffer space

5.2.3 Economics and Financing

The preparation of this guidebook coincides with a time of enormous uncertainty in the global financial sector, and a contraction in credit markets. These economic changes and stresses have significantly contributed to the barriers faced by developers and farmers attempting to finance digester projects.

This section identifies barriers to digester project financing, and suggests new approaches that may help address these barriers.

Many aspects of project economics and financing apply generally to many types of biomass-based, energy-producing systems. This crosscutting information is presented in Chapter 2 – Crosscutting Issues: Financing. A case study is included in Appendix 3. Information specific to agricultural digesters is presented below.

5.2.3.1 Project Economics

Operation and Maintenance Costs

Since there are many vendor choices for anaerobic digesters and CHP units, there also exists a range of vendor recommended operation and maintenance costs. The following are general operational and maintenance cost guidelines, which will be more or less relevant depending on the type of system installed:

- Annual average anaerobic digester service and maintenance costs are usually estimated on a per cents per kWh produced cost basis.
- Major anaerobic digester equipment components should have a life expectancy of 3-5 years (pumps, motors, impellers, etc.).
- Most major anaerobic digester roof systems have an anticipated life expectancy of 20 years.
- Reciprocal engine type gensets have varying estimated annual maintenance costs that are usually quoted on a cents per kWh produced basis. Different levels of service are offered. For example, service costs may not include consumables such as oil, filters, plugs, etc.; with/without emergency breakdown service; and parts and/or labor only.
- Microturbines have varying estimated annual maintenance costs, depending on the manufacturer, which are usually quoted on a cents per kWh produced basis.

Operation and Maintenance Guidelines for Cost Reduction:

- Instrumentation associated with anaerobic digester operation should be maintained and calibrated pursuant to manufacturer's recommendations, to insure continuous accurate data for optimal process performance.
- Anaerobic digester maintenance schedules should be followed pursuant to manufacturer's guidelines in order to optimize life expectancy and minimize service costs.
- Inert and/or indigestible quantities of organic waste feedstock introduced into an anaerobic digester can have performance impacts that may cause reduced digester performance, increased maintenance and/or shortened life expectancy.
- Poor quality digester feedstocks can negatively affect digester gas quality and may cause CHP unit damage and/or reduced performance. A good quality control process must be followed.
- Agricultural based anaerobic digester gas is generally cleaner than landfill gas and is usually closer in character to natural gas. Thus, CHP service and maintenance in such applications is closer to that anticipated for natural gas fired units.
- Ignoring mobilization and demobilization, service and maintenance costs on reciprocal CHP units tend to increase somewhat linearly as the units get larger in kW rating.
- The developer should be mindful of the vendor recommended tolerances for inlet digester gas qualities and required inlet manifold pressures when designing CHP systems, in order to optimize life expectancy, minimize down time and limit service and maintenance costs.
- Qualified maintenance personnel should service the various components so as not to invalidate equipment warranties.

5.2.3.2 Project Financing

Traditional financing models

The traditional source of finance for digester projects in the U.S. has been the farm-financed model, whereby the farm becomes the system purchaser, using existing banking relationships and lines of credit, supported by state and federal incentive and loan programs. This model places the burden of financing on the farm, which usually employs a project developer to design and construct the digester system.

Traditional lending requirements often include personal guarantees, long term fixed-price contracts for the sale of power, and equipment performance guarantees from manufacturers. However, these requirements are frequently not available.

An alternative to farm-financing of projects is the tax-equity investment model, a model commonly used to finance other types of renewable energy projects. For a more detailed discussion of this model, see Chapter 2 – Crosscutting Issues: Financing.

The European model

The farm ownership model common in the U.S. places a large burden on the farm to finance project development and to sustain project operation when the facility experiences operational problems. This model has seen limited success, as measured by the small number of digester systems installed in the U.S., as compared with the number installed globally.

A new model of third party ownership, or farm/developer partnership, similar to that which has helped support the rapid deployment of digester systems across Europe, addresses these issues. Typically, such a partnership will include an operating agreement covering system and process monitoring. Additional contracts can be established to provide biological laboratory support for the analysis of substrates, and for the design/change of substrate feed plans. Some manufacturers can also provide system maintenance and technology upgrades. In some cases this arrangement can be used to obtain extended manufacturer warranties. In sum, the European partnership model offers significant additional support to the owner/developer, as compared to the traditional U.S. ownership model, in which the purchaser of the digester is left to operate it alone.

In addition to this new partnership model, the European experience suggests the adoption of complete mix anaerobic digesters, a more sophisticated design than the plug-flow systems traditionally used in the U.S. The additional integration of controls technology, along with the use of organic waste streams, results in a system that yields higher rates of biogas production (see Table 9). This improved system also requires more capital investment, greater hands-on support, and constant monitoring and analysis; and the greater system complexity may be perceived by lenders and developer/owners as posing greater investment risk. While this is an understandable initial reaction, the positive performance history of these system designs should support borrowing requests and investment decisions.

Table 9. Capacity Potential Based on Manure and Organic Waste % of Total Mix.

Manure as % of total mix	**Organic Waste as % of total mix**	**Capacity potential**
100%	Zero	470kW
85%	15% Brewers grains	675kW
85%	15% Food/bakery Prep waste	790kW

Note: Values assume manure from 2,000 milking cows, and are based on guidelines from digester manufacturers, available online at www.lfl.bayern.de/ilb/technik/10225/?sel%20list=26%2Cb&strsearch=&pos=left.

On-site and centralized digester models

Economics is likely to be the main factor determining whether any proposed anaerobic digester will be used for the sole benefit of a single host entity (usually a farm), or whether the digester is placed at a central location for the benefit of many stakeholders. While not a hard and fast rule, historical data indicates that small (less than 250 kW electrical generation potential) complete mix anaerobic digester facilities on individual farms, with only manure as an input substrate, are unlikely to yield a high enough return on investment to be cost effective. This situation is due in part to the higher initial capital costs of this type of digester versus a plug-flow type, and the typically lesser efficiencies of the smaller CHP units. Anaerobic digesters in the range of 450-500 kW electrical generation potential tend to be cost effective in part due to the more efficient gensets available in that power range, and in part due to the more favorable economics of the larger CHP units.

When small farms (NYSDEC defines a small herd as less than 200 mature dairy cows) don't have favorable economics to support their own anaerobic digester, a shared, centralized project, with each participating farm bringing its waste materials to the community digester, can offer a solution. Such a community system, by virtue of its size, may be able to provide more favorable economics than any of the participants could achieve individually. In addition, a centralized system can sometimes more easily accommodate the acceptance of supplemental organic food wastes, which can provide both a tipping fee and enhanced biogas production. The success of such a system depends in part on the proximity between participating farms and the availability of other waste sources. The energy potential of the waste streams versus the cost to transport is a critical factor in determining the economic viability of a project; since manure typically has very high water content, transporting it over long distances is not generally a cost-effective option. Appropriate background research should be done, coupled with an economic model incorporating the necessary engineering/business parameters, to determine a potential project's feasibility.

Assessing investment in additional equipment/integration of existing operations/systems

As indicated above, the capital costs of the facility and the operations and maintenance costs must be weighed against the revenue streams that the digester facility produces. Tipping fees for incoming organic waste streams, electricity and heat produced, the use/sale of the post digested liquids and solids, and the potential sale of carbon credits all may produce additional revenue beyond the value of the energy produced.

The existing farm operations and associated equipment must be evaluated holistically. A properly designed anaerobic digester facility may reduce the operational load on existing farm systems, improve their performance, and extend their life expectancy.

Assessing the integration of new equipment and processes with existing systems should include an evaluation of the following:

- Physical interconnection points (to determine any incompatibilities, such as inconsistent pipe sizes)
- Pump and flow rates (to identify unmatched pumping rates)
- Location and type of waste storage, potential for run-off, and leverage of existing infrastructure
- Access to site for deliveries of waste
- Location of emergency biogas flare
- Existing utility interconnection at farm
- Existing revenue-producing farm operations (to ensure that digester operation will not encumber them)

5.2.4 Energy Conversion

5.2.4.1 Gas Treatment

The byproducts of anaerobic digestion are the post digested solids (digestate), the post digested liquids (wastewater) and digester gas (with methane as its most valuable constituent). Digester gas has approximately 55% to 65% of the British Thermal Units (Btu) value of natural gas or about 550 to 650 Btu per cubic foot, in large part because the digester gas is only about 60% methane, with most of the remainder comprised of carbon dioxide. Digester gas from agricultural based materials is much cleaner than gas derived from landfills, and is closer in composition to natural gas. However, digester gas does require some treatment before it can be used as a fuel, because a number of trace contaminants, including hydrogen, nitrogen, hydrogen sulfide, and water vapor, are usually present in varying amounts. Cooling the gas, and removing moisture and trace contaminants, will result in lower genset maintenance costs and increased operating efficiencies when the gas is combusted. Operational requirements of the combustion system will determine how pure the biogas must be.

5.2.4.2 Combustion Technologies

As previously discussed, methane produced by digesters of less than about 1.5 MW electrical equivalent output capacity is typically used as fuel for CHP units (gensets).

The two most commonly used types of CHP units are reciprocal engines and microturbines. Reciprocal engines are of the type found in most automobiles, and are the type most commonly used for digester gas CHP applications. They can range in size from six cylinders for low power units to more than 20 cylinders for larger units. Power production from reciprocal units typically ranges from 20 kW to more than 2 MW. The operational uptime for such units is around 95%.

There are numerous manufacturers of reciprocal engine gensets including:

- Dreyer/Bosse
- Caterpillar
- Waukesha
- Jenbacher
- I Power
- Guascor

Microturbines, within certain power ranges, are another option for CHP unit selection. These units can range in power from around 30 kW to 1 MW. Their operational uptime is generally estimated to be around 99%. Manufacturers of these units include Capstone and Ingersoll Rand.

Reciprocal engines and microturbines are not considered equal with regard to their tolerance for variations in digester gas quality. Reciprocal engines are generally more forgiving with regard to inlet gas temperature ranges (-20 to +140 degrees Fahrenheit), pressure (around 1 psig) and relative humidity (no liquid water). Microturbines prefer inlet gas temperature ranges from -4 to +122 degrees Fahrenheit, inlet gas pressure around 90-95 psig and little to no relative humidity. They are, however, more tolerant of hydrogen sulfide.

CHP units in general tend to be susceptible to sulfur, moisture and other contaminants in the gas. A chiller or similar device is usually placed upstream of the genset(s) to keep moisture vapor levels acceptable.

In reciprocal engines, heat is derived from the engine block jacket (190-200 degrees Fahrenheit) and the exhaust manifold (800-1,000 degrees Fahrenheit). The heat available from the engine block jacket is a given since the block needs to be cooled or the engine would overheat and cease operating. To use the exhaust manifold heat requires additional equipment from the CHP vendor. This equipment may be cost effective to install as long as there is a need for the additional heat. In microturbines, process heat is captured using a heat exchanger or recuperator.

5.2.4.3 Unit Efficiency

The choice of CHP type and size will have a large impact on overall system efficiency as well as on the unit's electrical and thermal efficiencies. Most manufacturers provide tables that illustrate the efficiency ratings of their various offerings. The ability of the digester to produce a constant stream of biogas with consistent characteristics also has a strong bearing on the performance of the CHP unit.

Efficiency will also be a function of maintenance. Therefore, consideration should be given to the projected operation and maintenance costs of the CHP unit, the availability of trained technical support, required operations/maintenance intervals and availability of spare parts/consumables. Financial considerations should include the method by which routine maintenance will be allotted and provided. This analysis should be performed as part of the project economic analysis and due diligence discussed later in this chapter.

CHAPTER 6 – BIOMASS DIRECT FIRING AND CO-FIRING WITH FOSSIL FUELS

6.1 INTRODUCTION

The simplest, most direct method of generating energy from biomass is to burn it. But while biomass combustion may be simple in theory, getting from theory to practice requires complex decision-making with regard to fuels, combustion and generation systems, auxiliary systems, siting, team building, permitting and financing. In all these areas, details count, especially when tradeoffs are being considered. For example, a combustion system that offers greater fuel flexibility can lower long-term fuel costs and supply interruption risks, but may require a larger up-front investment, more sophisticated process controls, and more frequent maintenance. This kind of tradeoff can only be decided based on the needs and resources of the individual project.

For this reason, it is likely that no two biomass combustion facilities will be the same. Although some off-the-shelf system components are available, and fuels are increasingly available as standardized products, the development of a biomass plant is driven to a large degree by local needs, regulations and resources, and as such, each project will be individual in nature. This chapter is designed to provide baseline information, against which the specific needs of each project may be weighed.

Some assumptions have been made in presenting this material. Chief among these is the assumption that any direct-combustion biomass system generating electricity at 10 MW capacity and smaller —the capacity range addressed by this guidebook—will also need to capture waste heat, in order to be economically viable. That is, all small to medium sized biomass direct-combustion systems are assumed to be CHP (combined heat and power, or “co-gen”) systems. Such systems are generally scaled according to the thermal needs of a host site, with electricity production a secondary consideration, for the simple reason that current biomass direct combustion technologies generate heat much more efficiently than electricity.

6.2 BIOMASS DIRECT FIRING

6.2.1. Energy Conversion

The choice of an energy conversion system and system components is a fundamental decision that will impact every aspect of biomass facility development and operation. While some off-the-shelf system components are available, most systems will be designed to fit the specific needs of the user or host facility, taking into account such variables as location, energy requirements, cost, feedstock availability, zoning and permitting requirements, and environmental regulations. In the case of a system conversion, where an existing fossil fuel-burning boiler is retrofitted to burn biomass, the configuration of the existing system will also have to be taken into account.

6.2.1.1 Choosing an Energy Conversion System

There are a number of available combustion technologies from which to choose when building or converting a system to burn biomass fuels. Among the first items to consider will be the needs of the host facility, if the system is to be used in an industrial context; the economics of system installation and operation, including revenue streams and the probable payback period; and the availability, price, quality, supply reliability, and handling requirements of fuels.

Because reliable fuel supplies will need to be secured, and fuel prices negotiated in order to determine the project payback period and obtain financing, it may be necessary in some cases to begin with the question of feedstock availability. However, in most cases it will be equally if not more important to first ascertain the energy (electric and thermal) needs of the facility to be supplied by the biomass combustion system. The needs of the host facility will often determine the choice of combustion technology and system componentswhich in turn will inform the choice of feedstocks to be obtained (McArdle, 2009).

Unless the price of electricity is very high or biomass fuels are available at no or very low cost, it will probably not prove economically feasible to combust biomass for electricity production alone. Therefore, a very important consideration is whether there is an on-site or nearby use for the waste heat from combustion, and in what form that heat will be needed. Capturing waste heat will increase the fuel efficiency of the system dramatically, from 20-25% for electricity production only, to as much as 75% (generally the greatest efficiency obtainable for biomass fueled systems) if all heat from the combustion process can be captured and used (Doshi, 2009). Because it is more efficient to burn biomass for heat than for electricity production, maximum efficiency will be obtained by scaling the combustion system to meet the thermal need rather than an electricity production target.

An exception to this general rule may be made in cases where the generation of electricity can provide alternative revenue streams. Currently, the environmental incentives for biomass combustion reward electricity production rather than heat production. For example, selling steam instead of electricity can mean giving up renewable energy credits. For this reason, a developer may choose to generate more electricity than would otherwise be economical. However, it is important to keep in mind that the markets for RECs, carbon credits and the like are relatively new; in addition, the value of these environmental products is not strictly market-based, but is significantly influenced by legislative and policy decisions at the state, regional, national and international levels. It is therefore very difficult to predict the future value of the "green" products of biomass combustion (McArdle, 2009).

Assuming heat is to be used on-site, the peak heat load of the host facility will be a key value in sizing the biomass system to be installed. Generally, the hourly heat requirement determines the thermal capacity of a system, while the annual energy requirement determines the economics of a system.

This is because the thermal capacity of a biomass system is based on the peak hourly use, which is the heat requirement for the coldest hour of the coldest day of the year. A system must be able to meet all of a facility's thermal heating needs without back-up during that hour; therefore, the boiler is sized to accommodate that demand. However, since the system will not run at full thermal capacity most hours of the year, the economics of the system are based on how much fossil fuel a facility would use over the course of an entire year, and how much of that fuel will be displaced by biomass.

For example, a building has a peak hourly demand of 0.3 million British thermal units (MMBtu) of thermal energy per hour during the coldest hour of the year, so a 0.3 MMBtu/hr boiler is installed, with a combustion system sized accordingly. 0.3 MMBtu/hr equates to approximately three gallons of oil burned per hour. However, over the course of a year, the building actually uses 1,755 gallons of oil to meet its heating needs. If the biomass system replaces 90% of the facility's annual oil use, the economics of that system are calculated using the annual fuel cost savings (Doshi, 2009).

As noted above, the choice of combustion technologies will depend somewhat on what form of waste heat is needed. If steam is needed, a steam turbine or engine will be required; if hot water is needed, an organic Rankine cycle (ORC) system may be used instead. The ORC is distinguished from the Rankine cycle, which is the basis for standard steam turbine operation, by its use of organic, high molecular mass working fluid (refrigerants or hydrocarbons) having a lower boiling point than water. This allows ORC systems to achieve higher heat recovery efficiencies. The ORC is just beginning to enter the U.S. market, although it is widely used in Europe, and should soon become commercially available in the U.S. (Doshi, 2009).

Within the range of traditional steam boilers, there are several types from which to choose, but the most commonly used fall into two main categories: grate (stoker) systems, and fluidized bed systems. The choice will be determined by the fuel type to be used, the amount of feedstock flexibility desired, size and efficiency limitations, and financial considerations. Generally, a fluidized bed system will provide greater flexibility in handling variations in fuels, but because of the higher costs associated with this design, it may only be financially feasible at the 5-10 MW size range (and many sources recommend these systems be used for systems of at least 20 MW capacity). In the 2-5 MW range, a moving grate design may be more cost-effective.

Another decision to be made will be whether to use a single combustion chamber design, or a staged combustion design that uses two or more chambers to combust the fuel in different phases (the first combustion chamber burns solid fuel, and the second burns the uncombusted gases). Biomass has a relatively high volatile content (60%-80%), and this makes staged combustion a particularly suitable choice. Staged combustion eliminates the need for heat extraction by tubes immersed in the bed, avoiding the problem of erosion of in-bed tubes, which is common in bubbling-bed boilers (Basu, 2006). Staged combustion designs are available for both grate and fluidized bed type systems, as well as for various other types of combustion systems.

Biomass combustion systems

There are several types of systems available for burning biomass that are briefly discussed here. Each has both advantages and disadvantages. The best technology choice ultimately depends on the needs of the facility and the type of fuels to be combusted. The major attributes of these systems, including fuel types and average capacity ranges, are summarized in Table 10. Table 11 lists the significant advantages and disadvantages of each.

Grate combustion systems
Grate combustors use an automatic feeder to distribute fuel onto a grate, where it burns. Combustion air enters from below the grate. In stationary grate systems, ashes fall into a collection pit; traveling grate systems have a moving grate that drops the ash into a hopper. Varieties include fixed, moving, travelling,[28] rotating and vibrating grate systems. This type of system requires particles of sufficient size that they will not fall through the grate with the ash.

Fluidized bed systems
Fluidized-bed systems burn biomass fuel in a hot bed of granular material, such as sand. Injection of air into the bed creates turbulence that distributes and suspends the fuel. Under these conditions, the fuel particles behave much like a boiling liquid. This design increases heat transfer and allows for operating temperatures below 972° C (1700° F), reducing nitrogen oxide (NO_x) emissions.

Fluidized-bed combustors can handle high-ash fuels, stringy fuels and agricultural residues, which are problematic when used in a grate combustor (straws and grasses contain potassium and sodium (alkali) compounds that combine with silica, also present in agricultural residues, causing slagging and fouling problems in conventional high-temperature wood combustion equipment). Fluidized-bed systems also have infinite turndown.[29] However, they tend to be more expensive than other types of combustion systems and require high energy inputs during operation.

Fluidized-bed systems come in two basic varieties: bubbling fluidized bed (BFB), and circulating fluidized bed (CFB). The main difference is that CFB systems use smaller bed particles and higher air injection velocities, so that the bed material (fine sand) exits the combustion chamber with the flue gas. It is then separated and fed back into the combustion chamber along with any other unburned particles. CFB systems can achieve better heat transfer, higher combustion efficiencies and lower flue gas flow. However, they tend to be larger and thus more expensive than BFB systems, and are probably appropriate only for larger biomass projects.

[28] Moving and travelling grate designs employ different methods of moving the fuel bed. In a moving grate furnace, the grate is divided into several sections that move back and forth; this motion transports the fuel along the grate. In travelling grate furnaces, the entire grate circulates in an endless loop through the combustion chamber, like a moving staircase, carrying the fuel along with it.
[29] Turndown is generally defined as the ratio of maximum heat output to minimum heat output of a combustion system. High turndown indicates that a system can operate along a wide range of output values. This is usually considered to be advantageous because it allows the combustion system to be adjusted up or down according to a greater range of load conditions, thus improving fuel efficiency at low load levels.

Pile burners
This is an older technology that probably will not apply to biomass systems except in cases where existing coal-fired pile burners may be retrofitted to allow co-firing with biomass (combustion system choices for co-firing applications are discussed at greater length in the co-firing section of this chapter). Pile burners consist of cells (sometimes called "wet cells"), each having an upper and a lower combustion chamber. Biomass fuel burns on a grate in the lower chamber, releasing volatile gases that burn in the upper (secondary) combustion chamber. They are similar to grate combustors, except that air for combustion comes from above the pile rather than from below.

Pile burners are simple in construction and relatively inexpensive. They can handle stringy materials but have poor turndown. In addition, older pile burners must be shut down periodically for ash removal, a feature that has rendered them obsolete with the development of more efficient combustion designs with automated ash removal systems (Oregon biomass webpages, 2009).

Suspension and cyclone burners
Suspension and cyclone burners have been used for many years for burning coal, but have relatively recently been adapted to handle wood fuels. Suspension burners require fuel in the form of pulverized fine particles 6 mm in diameter or smaller and having a maximum moisture content of 15%; cyclone burners require fuel of a maximum 3.5 mm size and 12% moisture content. The fuel is suspended in the combustion chamber, either by forced air or by centrifugal force.

This type of combustion system offers higher efficiencies of approximately 75%-80%, quick response to swing loads and high turndown ratios. By comparison, stoker grate or fluidized bed systems, which fire wet wood chips of 50%-55% moisture content, offer approximately 65% efficiency. But this higher efficiency is offset by the cost of drier fuel and smaller particle sizes. In addition, special burners, such as scroll cyclonic burners and vertical-cylindrical burners, are required (UN FAO, 2009).

Whole Tree Burners
Whole tree burners essentially resemble a gigantic pile burner that can combust entire trees or tree segments up to 20 feet in length. This eliminates the need for wood chipping or pulverizing, but requires an extensive dedicated fuel supply system that allows for harvesting, transporting, storing and drying whole trees. It also requires a dedicated feedstock supply system that grows short rotation woody crops having short branches, so that the trees can be easily bundled and transported in stacks. The system is designed to be self-contained and self-sustaining, with feedstocks grown near the combustion facility and ash used to enrich the soil for subsequent crops of trees. Whole tree burners are a new technology that is still in the demonstration stage. Prototypes have been built and tested in Minnesota (Ragland, et al, 2005).

Table 10. Biomass Power Technology Fuel Specifications and Capacity Range. Source: Adapted from U.S. DOE Biomass Energy Data Book. Compiled by Lynn Wright, Oak Ridge, TN, with additional data added by Pace Energy and Climate Center.

Biomass Conversion Technology	Commonly used fuel types[a]	Particle Size Requirements	Moisture Content Requirements (wet basis)[b]	Average capacity range
Stove/Furnace	solid wood, pressed logs, wood chips and pellets	Limited by stove size and opening	10 – 30%	15 kWt to ?
Pile burners	Virtually any kind of wood residues[c] or agricultural residues[d] except wood flour	Limited by grate size and feed opening	< 65%	4 to 110 MWe
Pile burner fed with underfire stoker (biomass fed by auger below bed)	Sawdust, non-stringy bark, shavings, chips, hog fuel	0.25-2 in (6-38 mm)	10-30%	4 to 110 MWe
Stoker grate boilers	Sawdust, non-stringy bark, shavings, end cuts, chips, chip rejects, hog fuel	0.25 – 2 in (6 -50 mm)	10-50% (keep within 10% of design rate)	20 to 300 Mwe many in 20 to 50 MWe range
Suspension boilers Cyclonic	Sawdust. Non-stringy bark, shavings, flour, sander dust	0.25 in (6 mm) max	< 15%	many < 30 MWe
Suspension boilers, Air spreader-stoker	Wood flour, sander dust, and processed sawdust, shavings	0.04 in -0.06 in (1-1.6 mm)	< 20%	1.5 MWe to 30 Mwe
Fluidized-bed combustor (FB- bubbling or CFB-circulating)	Low alkali content fuels, mostly wood residues or peat, no flour or stringy materials	< 2 in (<50 mm)	< 60%	Many at 20 to 25 MWe, up to 300
Co-firing[e]: pulverized coal boiler	Sawdust, non-stringy bark, shavings, flour, sander dust	<0.25 in (<6 mm)	< 25%	Up to 1500 MWee
Co-firing: cyclones	Sawdust, non-stringy bark, shavings, flour, sander dust	<0.5 in (<12 mm)	10 – 50%	40 to 1150 MWee
Co-firing: stokers, fluidized bed	Sawdust, non-stringy bark, shavings, flour, hog fuel	< 3 in (<72 mm)	10 – 50%	MWee

a) Primary source for fuel types is: Badger, Phillip C. 2002. *Processing Cost Analysis for Biomass Feedstocks*. ORNL/TM-2002/199. Available at http://bioenergy.ornl.gov/main.aspx (search by title or author).
b) Most primary biomass, as harvested, has a moisture content (MC) of 50 to 60% (by wet weight) while secondary or tertiary sources of biomass may be delivered at between 10 and 30%. A lower MC always improves efficiency and some technologies require low MC biomass to operate properly while others can handle a range of MC.
c) Wood residues may include forest logging residues and storm damaged trees (hog fuel), primary mill residues (e.g. chipped bark and chip rejects), secondary mill residues (e.g. dry sawdust), urban wood residues such as construction and demolition debris, pallets and packaging materials, tree trimmings, urban land clearing debris, and other wood residue components of municipal solid waste (as wood chips).
d) Agricultural residues may include straws and dried grasses, nut hulls, orchard trimmings, fruit pits, etc. Slagging may be more of a problem in some types of combustion units with high alkali straws and grasses, unless the boilers have been specially designed to handle these type fuels.
e) The biomass component of a co-firing facility will usually be less than the equivalent of 50MWe.

Table 11. Significant Advantages and Disadvantages of Each Biomass Combustion System. Source: Loo, et al, 2008; with additional material by Pace Energy and Climate Center, 2009.

Combustion technology	Advantages	Disadvantages
Grate furnaces	Low investment costs for plants <20MW_{th}[a] Low operating costs Low dust load in the flue gas Less sensitive to slagging than fluidized bed furnaces	Usually no mixing of wood and herbaceous fuels possible (special construction needed to accommodate such mixing) Efficient NO_x reduction requires special technologies High excess oxygen (5-8vol%) decreases efficiency Combustion conditions not as homogeneous as in fluidized bed furnaces Low emission levels at partial load operation require a sophisticated process control
Underfeed stokers (fixed grate)	Low investment costs for plants <6MW_{th} Simple and good load control due to continuous fuel feeding and low fuel mass in the furnace Low emissions at partial load operation due to good fuel dosing Low flexibility in regard to particle size	Suitable only for biomass fuels with low ash content and high ash-melting point (wood fuels) (<50mm)
Bubbling fluidized bed	No moving parts in the hot combustion chamber NO_x reduction by air staging works well High flexibility concerning moisture content and kind of biomass fuels used Low excess oxygen (3-4 vol%) raises efficiency and decreases flue gas flow	High investment costs, interesting only for plants >20MW_{th} High operating costs, including energy intensive operation Reduced flexibility with regard to particle size (<80mm) Utilization of high alkali biomass fuels (e.g. straw) is critical due to possible bed agglomeration without special measures High dust load in the flue gas Loss of bed material with the ash without special measures
Circulating fluidized bed	No moving parts in the hot combustion chamber NO_x reduction by air staging works well High flexibility concerning moisture content and kind of biomass fuels used Homogeneous combustion conditions in the furnace if several fuel injectors are used High specific heat transfer capacity due to high turbulence Use of additives easy Very low excess oxygen (1-2vol%) raises efficiency and decreases flue gas flow	High investment costs, interesting only for plants >30MW_{th} High operating costs, including energy intensive operation Low flexibility with regard to particle size (<40mm) Utilization of high alkali biomass fuels (e.g. straw) is critical due to possible bed agglomeration High dust load in the flue gas Loss of bed material with the ash without special measures High sensitivity concerning ash slagging
Pulverized fuel furnaces	Low excess oxygen (4-6vol%) increases efficiency High NO_x reduction by efficient air staging and mixing possible if cyclone or vortex burners are used Very good load control and fast alteration of load possible	Particle size of biomass fuel is limited (<10-20mm) and expensive to achieve High wear rate of the insulation brickwork if cyclone or vortex burners are used An extra start-up burner is necessary

a. MW_{th} denotes the thermal power produced.

Regardless of the type of combustion system employed, biomass fuels can present a range of challenges to efficient plant operation, including high and inconsistent moisture content, slagging and fouling, sintering, corrosion, and ash and flue gas production. Auxiliary systems, sophisticated process controls, and periodic maintenance may be required to address these issues. Fuel characteristics and auxiliary systems are discussed in more detail below.

6.2.2 System Processes and Efficiency

Plant efficiency measures

There are a number of ways to increase the thermal efficiency of biomass combustion. Chief among these are biomass drying, which can yield approximately 8.7% increase in thermal efficiency for a 20wt% (wet basis, or w.b.) decrease in fuel moisture content (see fuels section); and flue gas condensation. The latter will provide an average 17% increase in potential thermal efficiency, and in some circumstances can provide up to a 30% increase (depending on the load on the system). Installing a flue gas condensation unit can also provide a 40%-75% increase in dust precipitation rates, and this can be increased even further by placing an aerosol electrostatic filter behind the condensation unit. Dust precipitation rates of up to 99% can be achieved by combining these technologies (Van Loo, 2008).

Generally, flue gas condensation units are recommended for plants using wet biomass fuels (average moisture content of 40wt%-55wt% w.b.), where the return of the network of pipes is below 60 degrees C, and if the nominal boiler capacity is above 2 MW_{th}. The amount of energy recovery possible using a flue gas condensation unit depends on several variables, including the moisture content of the fuel, the amount of excess oxygen in the flue gas and the desired temperature of the return water. The latter depends on the quality of the heat exchangers, hydraulic installations and process control systems. It should be noted that if the condensate is too cold, it can react with the SO_2 in the flue gas to create sulfuric acid, which will corrode the condensation units (Van Loo, 2008). It is therefore very important to pay attention to the temperature in these units. Also, gas condensation units can easily become plugged (Doshi, 2009).

Other measures for improving thermal efficiency include decreasing O_2 content of the flue gas, reducing the organic carbon content in the ash, and decreasing the flue gas temperature at the boiler outlet. These measures each produce a relatively small increase in thermal efficiency.

Process Controls

Controlling operational processes is an important part of efficient and safe plant operation. Modern biomass combustion plants are increasingly automated, with sophisticated process controls. These include load, combustion, furnace temperature and furnace pressure controls. The purpose of process controls is to keep the combustion process operating at optimum efficiency, and to deal with variations in fuel characteristics and system load. Model-based and model predictive controls are also available to help optimize multivariable processes without resorting to the trial and error approach. Advanced sensoring techniques, such as software-based sensoring, can be used to estimate unmeasurable process quantities based on existing process measurements (Loo, *et al,* 2008).

Cogeneration

As previously mentioned, cogeneration (CHP) offers the potential to significantly increase plant efficiency through the capture and use of waste heat from the electricity production process. Biomass combustion facilities that produce electricity from steam-driven turbine-generators have a conversion efficiency of 17% - 25%. Using a boiler to produce both heat and electricity (cogeneration) improves overall system efficiency to as much as 75%. That is, cogeneration converts 75% of the fuel´s potential energy into useful energy in two forms: electricity and steam heat.

Two cogeneration arrangements, or cycles, are possible for combining electric power generation with industrial steam production. Steam can be used in an industrial process first and then routed through a turbine to generate electricity; this arrangement is called a bottoming cycle. In the alternate arrangement, steam from the boiler passes first through a turbine to produce electric power, after which the steam exhaust from the turbine is used for industrial processes or for space and water heating; this arrangement is called a topping cycle. Of the two cogeneration arrangements, the topping cycle is more common. It is frequently used with a back-pressure or extraction turbine. Combined cycles that integrate topping and bottom cycles in a sequential process are also possible (see 5.2.3, Electricity Generation Technologies).

6.2.3 Electricity Generation Technologies

Steam turbines

The steam turbine is a proven, mature technology available off-the-shelf in a broad range of capacities. It allows separation between the fuel and thermal cycle, enabling the use of fuel, such as biomass, that contains ash and other contaminants[30]. However, smaller capacity plants tend to be limited in fuel efficiency, especially when operating at low loads, and have relatively high investment levels and operations costs. Steam and power production are dependent on fuel quality and consistency; high quality steam is necessary for power production, and superheater temperatures (and efficiencies) can be limited due to corrosion and fouling at high temperatures (Loo, *et al,* 2008).

Because biomass combustion produces heat much more efficiently than it does electricity, it is likely that any moderate-sized biomass-fueled CHP system will be scaled to meet a thermal load. In this case, assuming that steam is needed, electricity may be generated by use of either a backpressure or an extraction turbine.[31] Backpressure turbines are well suited to small scale electricity generation of 0.5 – 5 MW with heat capture, while extraction turbines are better suited for electricity generation of greater than 5 MW capacity. Both types of turbine are generally used in topping cycles. They are discussed in more detail below.

Note that heat capture in plants using steam turbines reduces the efficiency of electricity production by about 10%; however, this small loss is more than compensated for by the large increase in overall fuel efficiency made possible by the capture and use of waste heat. It is also important to note that for electricity production in the 0.25 – 10 MW range, efficiencies at partial loads tend to be low.

Backpressure turbines
A backpressure turbine should be considered for boilers with steam flows of at least 3,000 lbs/hr, where the pressure drop between boiler and distribution network is at least 100 psig. If the system is being converted from an existing system, a backpressure turbine may be installed in parallel with a pressure-relief valve (boiler steam throughput will have to be increased by 5-7% to maintain previous levels of process steam). Off-the-shelf backpressure steam turbines are available in various capacity ratings, with 50 kW rated units representing the smaller end of the spectrum. Capital costs range from about $700/kW for a small system (50 kW) to less than $200/kW for a larger system (>2,000 kW), with installation costs averaging about 75% of equipment costs. This type of system can generate electricity relatively cheaply, at efficiencies much greater than the average U.S. electric grid efficiency, meaning that the payback period may be relatively brief. Of course, this will depend on biomass fuel and electricity prices, and other variables (U.S. DOE Industrial Technologies Program; Loo, *et al,* 2008).

An advantage of backpressure turbines is that they depend on large quantities of low-pressure process steam, making them safer than high-pressure turbines and requiring fewer people for their operation.

Backpressure turbines are suitable for applications with an almost constant heat demand and, within a limited range of operation, the plant load may be varied to meet this heat demand. To

[30] One great advantage of steam turbines is that they are a closed thermal cycle technology. This means that the fuel combustion process is physically separated from the power generation cycle. The power generator (the steam turbine) uses a clean process medium (water) that cannot become contaminated with byproducts of the combustion process, such as ash particles.
[31] A third choice is a condensation or "condensing" turbine, but this technology does not allow for heat capture and is therefore not well suited for most biomass-fired systems; in addition, condensation turbines do not reach high efficiencies at a small scale. For this reason, condensation plants are typically scaled to produce at least 25MW and are dedicated electricity generators.

avoid damage to the plant in case of interrupted heat demand, an emergency cooler is recommended.

For more information about backpressure steam turbines, including formulas to determine the payback period, refer to the following documents:

- **Steam Tip Sheets #20 and #22, published by the Industrial Technologies** Program, Energy Efficiency and Renewable Energy, U.S. Department of Energy;
- "Improving Steam System Performance; A Sourcebook for Industry," also published by the U.S. DOE Industrial Technologies Program.

These and other relevant documents are available online at http://www1.eere.energy.gov/industry/bestpractices/.

Extraction turbines
Extraction plants may be extraction condensing plants or extraction backpressure plants. This technology combines the advantages of condensing and backpressure units, but is more complex. It allows for variable extraction of steam at an intermediate pressure and temperature for use in heat applications, with the remaining steam being used to drive an additional low-pressure section of the turbine in condensing mode (Loo, *et al,* 2008).

Alternative technologies: steam engines

Although steam turbines are the most commonly used technology for biomass-fueled electricity production, there are alternative technologies that are both mature and readily available. These include steam piston engines and steam screw engines.

Steam piston engines
Steam piston engines are available in capacities up to 1.5 MW per unit. They are modular in design, and may use single- or multistage steam expansion. Engine efficiency is greater with multistage units that can achieve efficiencies of up to 20% (corresponding with up to 14% electrical plant efficiency). They offer several advantages over steam turbines, including the fact that they are less sensitive to wetness and contaminants in the steam, require less sophisticated water quality management, and can even be operated with low-pressure, saturated steam (albeit with reduced efficiency), leading to investment savings on the boiler. They also have a higher part-load efficiency than turbines, reaching up to 90% efficiency at between 50% and 100% of nominal power. This makes them suitable for meeting a variable heat and electric load. Newer steam piston engines also allow oil-free operation, mitigating the need to add oil to the steam as was common in older engine designs (Van Loo, 2008).

Steam screw engines
For smaller scale power generation, steam screw engines may be used. These engines can operate under various steam conditions, including low steam conditions, superheated and saturated steam, and even wet steam and compressed hot water. The latter application may be especially appropriate for small CHP plants because no steam boiler is necessary. Screw steam engines use a closed oil cycle, so outlet steam does not contain oil traces (Van Loo, 2008).

Organic Rankine Cycle (ORC) systems

If heat offtake is needed in the form of hot water rather than steam, an organic Rankine cycle system may be used. These systems use organic oil or refrigerants rather than water as the process medium; because these fluids have lower boiling points than water, ORC systems may be operated at relatively low temperatures. Because no steam boiler is needed, ORC systems require lower up-front investment and maintenance expenses. ORC systems offer very high efficiency levels, are very safe, and, because they are closed-loop, no-pressure systems, operations can be automated to a high degree, which can result in operational cost savings. The technology is also very environmentally safe.

Organic Rankine cycle systems are widely used in Europe, but are not yet commercially available in the U.S. It is anticipated that this technology will soon find acceptance in the U.S. market. However, because they are new, early adopters may find it more time consuming and expensive to obtain permits and satisfy regulatory agencies unfamiliar with the technology (Doshi, 2009).

6.2.4 Auxiliary systems and supporting infrastructure

Typically, various auxiliary systems and supporting infrastructure will be required for any power generating facility. Many are common to all such facilities, but some are of particular relevance for biomass-fired facilities. These are discussed briefly below.

- **Fuel storage and drying facilities**
  The extent and complexity of on-site fuel storage and drying facilities will depend on how much space is available, as well as on the fuel requirements of the combustion system. If storage space is not available, just-in-time fuel delivery is possible, but may be more expensive. Frequently green wood chips are burned, with the moisture in the fuel being driven off in the early stages of the combustion process. This, of course, will have implications for operational efficiencies. Alternately, process heat may often be used to dry the fuel prior to combustion, at relatively low cost. Fuel storage and drying systems are discussed in greater detail in section 5.4.4, Biomass Fuel and Feedstock Handling and Processing.

- **Fuel feeding and handling systems**
  Any biomass-fed project will need fuel handling systems to move biomass fuels from the point of delivery through processing and storage areas and, ultimately, into the combustion area. The specific equipment used for this task will depend on the type of fuel used, the layout of the facility, and other project-specific needs. Fuel feeding and handling systems are discussed in greater detail in section 5.4.4, Biomass Fuel and Feedstock Handling and Processing.

- **Backup Generators**
  It may be desirable to have a backup power generation system in place. Generally, biomass combustion systems offer about 95% reliability. If, for contractual, insurance or financing reasons, a greater degree of reliability is needed, a backup system, such as a natural gas- or diesel-fired boiler, may be needed. Having such a backup system in place also allows the biomass combustion system to be taken off-line from time to time for maintenance.

  Although properly designed biomass-fed systems are no less reliable than fossil fuel-fed electricity generation systems, unfamiliarity with these technologies and fuels has sometimes led financiers to request that backup systems be provided. This trend seems to be declining as biomass systems become more generally understood. For more information on financier requirements, see section 5.5.3, Financing.

- **Water purification**
  It is important to understand that the use of a steam turbine requires extremely pure process water, at high pressures. During vaporization, salts contained in the water remain in the boiler, where they can damage equipment. For this reason, water used in steam turbines must be continuously desalinated and purified, and pure fresh water must be continuously added to the system to replace steam losses. Drinking water in most municipal water systems is not pure enough for this purpose, as it is typically chlorinated, and is likely to contain minerals; nor should untreated groundwater be used for this purpose. For these reasons, on-site water purification systems are a costly but necessary part of the steam turbine plant.

- **Electric interconnection**
  If the biomass facility is to sell electricity onto the grid, it will be important to choose a site that is close to electrical lines that have sufficient excess carrying capacity. At smaller electrical generation capacities a distribution line may suffice, but it is also possible that the facility will need to access a small transmission line (13kV). If appropriate lines, switches, and other electrical grid infrastructure do not exist near the project site, upgrades may be required. The cost of such upgrades may be borne by the utility or the project developer, depending on the generation capacity of the project and the nature of the interface. This topic is discussed in more detail in Chapter 3 - Crosscutting Issues: Electrical, Thermal and Gas Offtake.

- **Roads**
  Most biomass-fed facilities will require frequent and regular fuel deliveries, most likely by truck. It is important to ascertain the carrying capacity of the roads that will be used for these deliveries, both in terms of traffic volume and, if bridges are present along the delivery route, of weight. Since area residents and businesses are likely to have concerns about the increase in truck traffic, it is a good idea to look at the suitability of local roads ahead of time. If the project site is accessed via a state highway, the New York State Department of Transportation (NYSDOT) may be asked to conduct an assessment of the traffic carrying capacity of the impacted sections of highway. Private traffic engineering firms may be retained to conduct assessments of non-state highways and local roads.

6.3 BIOMASS CO-FIRING

Co-firing with biomass has been the subject of extensive research, and there are numerous commercial-scale plants that practice co-firing. In the U.S., co-firing is most often practiced in large pulverized coal plants or grate burners. However, co-firing can also be applied in smaller scale facilities, and is therefore included in this guidebook. From the plant operator's point of view, co-firing may be an attractive option because it reduces emissions of some pollutants and greenhouse gases, and requires only a relatively inexpensive retrofit of the combustion and fuel handling systems. Thus, it may represent an economical way to comply with tightening emissions standards. A portion of the electricity produced through co-firing may also be eligible under the NYS RPS.

6.3.1 Background

Co-firing is generally the result of existing fossil fuel-fired plants (usually coal plants) being retrofitted to allow operators to blend biomass into the fuel mix. With most types of combustion systems, this requires relatively minor changes to the physical plant and fuel handling systems, and can be achieved at a much lower cost than would be required to build a new biomass-fired system. As a general rule, coal-fired boilers can be converted to safely use up to 15% biomass.

Co-firing has been the subject of increasing interest around the world, due mostly to concerns about global warming. Since biomass, with some safeguards, can be considered to be carbon-neutral over its life cycle (the carbon emitted when biomass is burned is equal to the carbon taken up by the next generation of biomass as it grows), co-firing biomass with fossil fuels can help reduce life-cycle CO_2 emissions and, in some cases, will generate renewable energy or CO_2 abatement credits[32]. Co-firing also helps reduce SO_2

[32] The degree to which biomass combustion reduces greenhouse gas emissions relative to fossil fuel combustion, on a life-cycle basis, depends a great deal on the harvesting/farming practices used to supply biomass feedstocks. For example, waste feedstocks generally have a much lower carbon footprint than farmed feedstocks. In some cases, sustainability standards will apply (such as the NYS RPS, which requires biomass projects to employ sustainable forestry standards). For more information on regulatory requirements, see Chapter 1 – Crosscutting Issues: Environmental Regulations and Permitting.

and perhaps NOx emissions.[33] Reduced use of fossil fuels is also associated with reduced environmental damage from mining and drilling for these fuels.

There are potential negative consequences of combusting biomass to be considered as well, including the cost of converting equipment to accommodate co-firing, and the potential for increased operations and maintenance costs. Depending on the project location, securing reliable biomass fuel sources may also be challenging and/or expensive. Co-firing with biomass also typically results in modest reductions in boiler efficiency, which limits the economic value of biomass fuels. Incentives for biomass use in electricity production and for reduced greenhouse gas emissions may be available to help offset such added costs.

6.3.2 Risks

There are two types of risks particularly associated with biomass co-firing:

- Reductions in plant availability and operational flexibility; and
- Increases in maintenance and replacements costs.

The key technical risk areas for biomass co-firing are:

- Fuel preparation, processing and handling;
- Combustion related issues such as flame stability and burnout;
- Ash related issues; and
- Emissions and other environmental impacts.
  (Loo, *et al,* 2008)

Converting an existing coal-fired boiler to accommodate coal-biomass co-firing requires careful consideration of biomass fuel properties that can create challenges for power plant operation. For example, wood ash contains alkaline metals that can foul heat transfer surfaces; therefore, careful attention must be paid to ash content, chemical composition and melting behavior, which is influenced by the presence and concentration of elements such as alkali metals, phosphorous, chlorine, silicon and calcium. It is also important to understand how to achieve an optimum balance in these fuel-bound elements when co-firing biomass. An example of this is co-firing fuels containing sulfur and aluminium silicate, such as peat or coal, with chlorine-bearing fuels to prevent the formation of alkaline and chlorine compounds on boiler heat transfer surfaces. Because high steam temperatures increase the risk of hot corrosion, biomass chlorine concentrations should be less than 0.5w-%, or even 0.1w-%, depending on the proportion of chlorine-bearing fuels in the overall fuel mix.

Biomass fuels possess a number of characteristics that cause them to behave differently than coal when combusted:

- Pyrolysis starts at lower temperatures for biomass fuels
- Biomass contains more volatile matter, which makes a greater fractional heat contribution (approximately 70%, compared with 30-40% in coal)
- The specific heating value of volatiles in kJ per kg is lower for biomass
- Biomass char has more oxygen, is more porous and more reactive than coal char
- Biomass ash is more alkaline, which may aggravate fouling
- Unless it is pre-processed, biomass generally has a much higher moisture content (fresh wood typically contains 50% water by weight, as compared with 5% moisture content for bituminous coals)

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[33] NOx formation is a complex process. Research on NOx formation in co-firing has yielded contradictory results, with some studies indicating that the introduction of biomass reduces NOx emissions, and other studies indicating the opposite. Generally, NOx formation can be addressed by various means; how it is addressed in a given situation depends on the type of combustion system and fuel being used.

- Biomass fuels can be high in chlorine, and low in sulfur and ash content. When biomass is blended with coal, this can contribute to a number of problems, including:
    - Increased deposit formation
    - A shorter soot-blowing interval
    - Increased risk of corrosion of heat transfer surfaces requiring frequent cleaning of these surfaces
    - Bed material agglomeration in fluidized bed systems
    - Greater in-house power consumption
    - Higher flue gas temperatures

It is important to note that many of the above-listed problems can be minimized or avoided with proper fuel handling and pre-processing, and by using fuels appropriate to the specifications of the equipment (Veijonen, *et al,* 2003).

While all wood fuels can potentially present some combustion challenges, some, such as residues from the wood processing and construction and demolition (C&D) industries, can be particularly problematic. Waste plywood and particle board may be attractive feedstocks due to their low price, but these products contain glue, coating and shielding materials that can cause bed agglomeration, slagging, fouling and harmful flue gas emissions. By contrast, forestry products are "cleaner" and less problematic, but tend to cost more. Dedicated energy crops are highly reliable in terms of supply and consistency of quality, but are the most expensive category of biomass feedstock.

6.3.3 Onsite Fuel Handling and Pretreatment

Fuel pretreatment options must also be considered. The flow characteristics of biomass particles are largely determined by particle size, shape and moisture content, with smaller, dryer particles causing fewer handling problems than larger, wetter particles. Comminution and drying are therefore generally helpful, but the decision of whether and to what degree pretreatment is needed will most likely be an economic one. Pretreatment can reduce fuel handling and facility maintenance costs, and increase the energy value of the fuel, but it will also add to the cost of the fuel. Pretreatment may or may not be advisable depending on a number of variables, including the type of combustion system in use, the quality, moisture content and particle size of the fuel, the particle size of the coal, and the type of fuel handling and feeding equipment in use.

Note that biomass is generally more difficult to comminute than coal. While the milling systems used in pulverized coal-fired boilers are normally capable of pulverizing woody biomass to a suitable size, doing so requires significantly more energy than does pulverizing a like amount of coal (Van Loo, 2008).

Another factor to consider when contemplating biomass co-firing is the transportation of the fuel. Typically, the energy density of untreated waste fuels is quite low, meaning that transportation of these fuels over long distances is not likely to be economical. It is important, when planning a biomass co-firing facility, to analyze the amount of energy needed to transport, store, and process biomass fuels on-site.

While wood is by far the predominant biomass fuel for direct- and co-firing applications in New York, there are other biomass fuels, currently in the experimental stage that may become commercially available over time. Straw falls into this category. Although it has been widely used in Europe for many years, straw can present challenges for co-firing applications due to its low bulk density and high chlorine and potassium content. Straw-fired boilers tend to experience operational problems due to deposits and corrosion. For this reason, an advanced logistic system and proper combustion technology are necessary elements for any facility that intends to co-fire with straw.

For more information on biomass direct-fire fuels and feedstocks, see 5.4, Biomass Resource Assessment.

6.3.4 Environmental and Permitting Concerns

As noted elsewhere in this guidebook, biomass combustion differs from fossil fuel combustion in several important ways, and these differences have implications for the potential environmental impacts of biomass-fueled systems. With regard to co-firing, the potential environmental impacts of biomass combustion should be relatively small, given that co-fired systems generally limit the biomass portion of their fuel stream to 15% or less. However, retrofitting an existing fossil-fueled plant to allow co-firing may require repermitting, including an assessment of potential environmental impacts (see permitting). In any case, it is important to address all the potential environmental impacts, both positive and negative, when considering co-firing.

Of particular importance in New York State is the Renewable Portfolio Standard (RPS), which incentivizes electricity production from clean renewable energy sources, including qualifying biomass fuels. For cofiring systems, the percentage of the produced electricity that will qualify under the RPS corresponds with the percentage of the fuel stream comprising qualifying biomass. Guidelines for determining whether biomass fuels qualify are included in the RPS Biomass Guidebook, available online at http://www.nyserda.org/rps/RPS_Biomass_Guide.pdf. Note that sustainable forestry practices are an important part of the criteria for certain biomass fuels, and an approved forestry plan may be required for RPS qualification.

6.3.5 Co-Firing Combustion Systems

Different types of combustion systems offer different strengths and weaknesses with regard to co-firing. These are discussed briefly here.

Fluidized Bed Boilers

Generally, fluidized bed boilers (either bubbling fluidized bed (BFB) or circulating fluidized bed (CFB) systems) are considered most suitable for wood co-firing because they are extremely tolerant of variations in fuel quality and moisture content, achieve high combustion efficiencies, and have relatively low emissions profiles. Fluidized bed boilers can combust almost any fuel—even moist, heterogeneous fuels with low calorific value—so long as the calorific value is sufficient to heat the fuel, drive off moisture and preheat the combustion air. Fuel-to-steam efficiency typically exceeds 90%, even when burning low-grade fuels. The temperature in fluidized bed combustion is lower than in pulverized fuel combustion, with high combustion efficiency achieved by a relatively long residence time in the bed. Because of the relatively low combustion temperature (typically 850°C), thermal NO_x formation is not a problem. An additional benefit is that converting fluidized bed systems designed for coal to accept biomass co-combustion requires a relatively small investment.

Pulverized Fuel Boilers

If straw is to be used as a fuel, a pulverized combustion system may be preferable, as this design achieves the lowest levels of slagging, fouling and corrosion with straw fuels. Most biomass co-firing in the U.S. uses pulverized coal boilers. There are four basic ways to co-fire biomass in this type of system:

a. Small amounts of biomass can be fed with the coal into coal mills before being burned with the coal. This requires the least investment in fuel handling equipment, but carries the highest risk of fuel feeder malfunction.
b. Biomass can be handled, metered and comminuted separately, and injected into the coal feed upstream of or at the burners. This method requires the installation of biofuel transport pipes. Maintaining and controlling burner operating characteristics over the normal boiler load curve may also be more difficult using this method.

c. Separate handling and comminution of the biofuel can be followed with separate combustion using dedicated burners. This is the highest capital cost option, but creates the least risk to normal boiler operation.
d. The final option uses the biofuel as a reburn fuel for NO_x emissions control of the coal combustion. In this scenario, the biofuel is combusted in a reburn system located in the upper furnace. This type of system is still in the development stage.

The problem with all four options is that power output losses are almost inevitable, and the proportion of biofuel to coal is limited.

Another option for pulverized coal- or gas-fired boilers is using gasified biomass fuels. In this scenario, biomass fuels are pre-processed in a gasification plant and the resulting gas is burned in a boiler together with pulverized coal or natural gas (see Chapter 6, Biomass Gasification). Gasifier gas may be used in raw form, or further processed by a gas cooling and cleaning system, which increases investment costs but avoids problems associated with condensation of tars and dust that can form deposits on equipment. Gasification is also one of several methods that can allow electricity produced using low-quality, waste-derived and recycled ("adulterated") fuels to qualify under the NYS RPS (see NYS PRS Biomass Guidebook).

Grate Boilers

Grate boilers are suitable for many types of fuels including coal, wood fuels, waste fuels, peat and straw. Even fairly moist fuels can be used if this is taken into account in boiler design. Compared to fluidized bed combustion, grate boiler efficiency is lower and flue gas emissions are higher; grate boilers are also more sensitive to changes in fuel quality and moisture, and automation of grate combustion is difficult. However, the simple design typically requires a lower initial investment and low operations and maintenance costs.

Although grate boilers are not commonly used for multifuel combustion, co-firing in small power plants is relatively safe as the steam temperature is usually lower than 400°C and there is no risk of hot corrosion. However, attention must be paid to flue gas cleaning; for this reason, most grate boiler plants are equipped with cyclone or electric precipitators, a bag house, or gas scrubbers. Variation in fuel quality also poses challenges to fuel handling and feeding. And ash melting problems can occur, as combustion chamber temperatures may reach 1300-1400°C. Ash melting can be reduced by use of mechanical and water-cooled grates, and avoidance of preheated combustion air in the final burning area.

Grate boilers are available in various sizes, from 15 kW up to 150 MW, and in several different configurations, including fixed flat grate, fixed sloping grate, mechanical sloping grate and chain grate systems. There are also special grate types for specific fuels, such as waste incineration grates or cigar combustion grates for straw. The key issues in grate firing of biomass are ensuring homogeneous fuel particle size and quality, proper sizing of the combustion chamber and efficient mixing of the combustion air.

6.3.6 Co-Firing Checklist

A number of questions should be answered when considering biomass co-firing in an existing coal-fired boiler. These include:

- How will the fuel be fed into the boiler?
- Will a new burner configuration be needed?
- How will the introduction of the biomass fuel affect the chemical composition and quantity of flue gases? Will flue gas blower capacity need to be revised?
- How will co-firing with biomass, which contains more volatiles, affect boiler operation, furnace temperatures and flue gas temperatures?

- Will the introduction of the biomass fuel cause a risk of deposit formation on heat transfer surfaces? Will the introduction of the biomass fuel cause a risk of bed agglomeration in fluidized bed combustion systems?
- Will the presence of alkali metals in wood ash, and increased flue gas volume, affect the desulfurization system?
- Will the introduction of the biomass fuel affect SCR or SNCR systems?
- Will changes in fly ash composition and the mass flow rate affect electric precipitators or other types of flue gas filter?
- How will co-firing affect ash utilization possibilities?
- How will the burners, fuel processing and feeding systems, boiler automation and other boiler plant auxiliary equipment need to be altered to accommodate the introduction of the biomass fuel?

(Veijonen, et al, 2003)

6.4 BIOMASS RESOURCE ASSESSMENT

In the early stages of planning for the development of a biomass combustion facility, a thorough assessment should be made of the availability, quality, reliability and affordability of feedstocks. Feedstock supply chains are well developed in the Adirondack Mountains region, where there are longstanding markets for low-grade wood, and are emerging in the Finger Lakes region. In many other areas of the state, securing a reliable supply of appropriate and affordable biomass fuel may be among the most challenging aspects of developing a biomass combustion facility; however, doing so is key to a successful biomass direct-firing operation. Therefore, this should be among the first issues addressed.

Wood fuel sourcing issues, including fuel availability, quality and pricing, are addressed in Chapter 4 – Crosscutting Issues: Wood Fuels. Fuel-related issues specific to direct and co-fired biomass operations, such as the operational and maintenance impacts of various fuels, are addressed below.

6.4.1 General Properties of Biomass Fuels

Despite their wide variety of shapes and sizes, biomass fuels are surprisingly homogenous in many of their fuel properties. Nearly all have a gross heating value between 15-19 GJ/tonne (6,450-8,200 Btu/lb). Most agricultural residues fall on the lower end of this range (15-17 GJ/tone, or 6,450-7,300 Btu/lb), and most woody materials fall on the upper end of the range (18-19 GJ/tone, or 7,750-8,200 Btu/lb). The most important determinant of heating value is moisture content, which averages around 40% for green wood, 15%-20% for air-dried biomass and near 0% for oven-dried biomass. The energy density of biomass is typically lower than that of fossil fuels, even after densification; the ash content of biomass is also lower than that of most coals, and its sulfur content is much lower. Unlike coal ash, which contains toxins, most biomass ash may be used to enrich soils for farming.[34] Biomass is also easier than coal to gasify (see Chapter 6, Biomass Gasification) or process thermochemically to produce higher-value fuels, such as methanol or hydrogen (U.S. DOE Biomass Energy Data Book).

Some properties of biomass fuels can cause maintenance and emissions problems. For example, biomass fuels are generally high in alkalis such as sodium and potassium, which cause bed sintering, slagging and fouling; and chlorine, which causes corrosion and can lead to HCl emissions and dioxin formation. Frequently, the impacts of biomass fuel properties are somewhat dependent on the type of combustion system being used. For example, the high moisture content of biomass increases flue gas volume per unit heat release, which requires a larger cyclone size and back-pass width in CFB boilers. Some clean wood fuels have low ash content that can cause bed inventory problems and require periodic bed topping in fluidized bed systems. (Basu, 2006).

[34] This depends on the feedstock source. Some urban waste wood, for example, may contain metals and chemical contaminants that render the ash unsuitable for soil enrichment.

6.4.1.1 Assessing fuel characteristics

There are a number of important variables to be aware of when assessing biomass fuels. Even within fuel types, wide variance is to be expected. For example, moisture content can vary from 25wt% - 60wt% for bark and sawmill residues, to below 10wt% for dry wood chips.[35] Ash sintering temperatures can vary widely as well, from 800 to 1,700 degrees C. Pretreatment can control some variables, but increases fuel costs. The alternative to pretreatment is a more sophisticated combustion system that is able to accept more heterogeneous and low-quality fuels. This alternative will increase up-front costs, but can decrease fuel costs and fuel supply-related risk over the life of the project. Operations and maintenance costs will also vary based on fuel and system specifications.

Important biomass fuel parameters include particle dimensions, bulk and energy density, gross and net calorific value, and moisture content. Also important are levels of nitrogen, chlorine, sulfur, as well as other elements that will be present to varying degrees in the fuel. The major elements in biomass fuels, and their importance, are discussed briefly below. For more detailed values, ranges and technological methods for reduction of these elements, see Table 12.

- **Nitrogen:** The amount of nitrogen oxides (NO_x) formed during biomass combustion depends to a great degree on the amount of nitrogen (N) present in the biomass fuel. However, NO_x formation is also a function of combustion temperatures. Because most NO_x is formed when combustion temperatures are between 800 and 1,100 degrees C, hotter-burning biomass combustion systems will emit more NO_x than cooler-burning systems. NO_x reduction can often be achieved using primary measures such as carefully controlling air ratios and recirculating flue gases. If these measures are not successful, secondary measures, such as selective catalytic or non-catalytic reduction, may be used.

- **Chlorine:** Chlorine (Cl) is important for two reasons. First, it causes emissions of hydrogen chloride (HCl), which is associated with the formation of compounds that can present environmental and health hazards, such as polychlorinated dibenzo-p-dioxins and dibenzofurans (PCDD/F). Second, it has corrosive effects and can damage equipment. PCDD/F formation can be reduced by reducing the amount of fly-ash particles in the flue gas, making sure combustion is as complete as possible, and using fuel with low amounts of excess oxygen and low concentrations of Cl. A secondary approach is to install an efficient dust precipitation technology that operates at low temperatures (<200 deg. C).

- **Sulfur:** Sulfur (S) is important both because it causes sulfur dioxide (SO_2) emissions, and because it plays a role in corrosion processes. A large portion of S is bound in the ash, with the remainder being emitted with the flue gas as SO_2 and, to a lesser extent, sulfur trioxide (SO_3). The efficiency of S fixation in the ash depends on the concentration of alkaline earths (especially Ca) in the ash, as well as the efficiency and technology used for dust precipitation.

(Van Loo, *et al,* 2008)

[35] Wood fuels in New York State typically have a moisture content of between 30% and 55%, with 40% being average. Wood from unfamiliar sources should be assessed for moisture content, as this will impact both the monetary value of the fuel and its heating value.

Table 12. Guiding Values and Guiding Ranges for Elements in Biomass Fuels and Ashes. Source: Van Loo, et al (2008).

Element	Guiding concentrations in fuel wt% (d.b.)	Limiting parameter	Fuels affected outside guiding ranges	Technological methods for reducing to guiding ranges
N	<0.6	NOx emissions	Straw, cereals, grass, olive residues	Primary measures (air staging, reduction zone)
	<2.5	NOx emissions	Waste wood, fibre boards	Secondary measures (SNCR or SCR process)
Cl	<0.1	Corrosion	Straw, cereals, grass, waste wood, olive residues	Fuel leaching, automatic heat exchanger cleaning, coating of boiler tubes, appropriate material selection
	<0.1	HCl emissions	Straw, cereals, grass, waste wood, olive residues	Dry sorption, scrubbers, fuel leaching
	<0.3	PCDD/F emissions	Straw, cereals, waste wood	Sorption with activated carbon
S	<0.1	Corrosion	Straw, cereals, grass, olive residues	See Cl
	<0.2	Sox emissions	Grass, hay, waste wood	See HCl emissions
Ca	15-35	Ash-melting point	Straw, cereals, grass, olive residues	Temperature control on the grate and in the furnace
K	<7.0	Ash-melting point, depositions, corrosion	Straw, cereals, grass, olive residues	Against corrosion: see Cl
	-	Aerosol formation	Straw, cereals, grass, olive residues	Efficient dust precipitation, fuel leaching
Zn	<0.08	Ash recycling, ash utilization	Bark, woodchips, sawdust, waste wood	Fractioned heavy metal separation, ash treatment
	-	Particulate emissions	Bark, woodchips, sawdust, waste wood	Efficient dust precipitation, treatment of condensates
Cd	<0.0005	Ash recycling, ash utilization	Bark, woodchips, sawdust, waste wood	See Zn
	-	Particulate emissions	Bark, woodchips, sawdust, waste wood	See Zn
Explanations: Guiding values for ashes related to the biomass fuel ashed according to ISO 1171-1981 at 550 deg. C; analytical method recommended for ash analysis: pressurized acid digestion and inductively coupled plasma mass spectrometry (ICP) or flame atomic absorption spectrometry (AAS) detection; N and S analysis recommended: combustion/gas chromatographic detection; Cl analysis recommended: bomb combustion/ion chromatographic detection. d.b. = dry basis.				

Ash Content

Another important variable to be aware of is ash content. The ash content of a fuel is largely governed by the concentrations of ash-forming elements silicon (Si), calcium (Ca), magnesium (Mg), potassium (K), sodium (Na) and phosphorus (P). K, P and Mg are plant nutrients, and Ca is a liming agent, making these elements important in the use of ashes as fertilizer. They are also important in determining the optimum operating temperature for combustion systems, because they impact the melting temperature of ashes. For example, Ca and Mg increase the melting temperature of ashes, while K and Na decrease it; Si, in combination with K and Na, can lead to the formation of low-melting silicates in fly-ash particles. Knowing the concentrations of ash-forming elements in biomass fuels is therefore important for controlling ash sintering, melting and slagging. Furthermore, K and Na, in combination with Cl and S, play a major role in equipment corrosion.

Clean wood has a relatively low ash content, while some grassy fuels can have a much higher ash content; fuels contaminated with mineral impurities can also have high levels of ash (see Table 13).

Table 13. Ash Content by Fuel Type. Source: Leckner, et al (1993), as quoted in Loo, et al (2008).

Fuel Type	Ash Content as wt% (d.b.)
Bark	5.0-8.0
Woodchips w/ bark	1.0-2.5
Woodchips w/out bark	0.8-1.4
Sawdust	0.5-1.1
Waste Wood	3.0-12.0
Straw and Cereals	4.0-12.0
Miscanthus	2.0-8.0

Notes: Ash content measurement according to ISO 1171-1981 at 550 deg. C.
Wood product ash values range from soft wood (lower ash content) to hard wood (higher ash content).

Low ash content simplifies de-ashing, ash transport, storage, utilization and disposal, but can create bed inventory problems in some types of boilers. High ash content fuels generally have higher dust emissions; burning fuels with high ash content will impact the selection and design of several system components including the heat exchanger, cleaning system and dust precipitation technology.

Moisture Content

In addition to the elements listed above, the moisture content will directly impact the heating value of the fuel, and can have implications for fuel handling and pretreatment. Most smaller facilities will rely on their fuel supplier to deliver fuel that, while subject to expected seasonal fluctuations, meets agreed-upon standards for moisture content when averaged over a year. However, when buying fuel from an unfamiliar source, the moisture content should be measured at the time of delivery to ascertain that it is within acceptable ranges. On this basis, a calculation of net calorific value may be made. The price paid for the fuel may also depend on the results of this calculation.

For more information on biomass fuel characteristics, several online databases may be consulted. These are:

- BioBank, a project of the International Energy Agency, at www.ieabcc.nl
- BIOBIB, a project of the Institute of Chemical Engineering, Fuel and Environmental Technology at the University of Technology, Vienna, Austria, at www.vt.tuwien.ac.at
- Phyllis, a project of the Netherlands Energy Research Foundation, at www.ecn.nl/Phyllis

Additional information is available from biomass resource organizations such as the Biomass Energy Resource Center (BERC), at www.biomasscenter.org/.

6.5 PROJECT DEVELOPMENT

In addition to those technology-specific topics already addressed, there are many more general factors to be taken into consideration when developing a direct or co-fired biomass facility. These include siting and permitting processes, project financing, and energy offtake issues. Because these aspects of development are common to many types of biomass projects, they are handled in the three crosscutting issues chapters (Chapters 1, 2 and 3).

CHAPTER 7: BIOMASS GASIFICATION

This chapter provides an introduction to biomass gasification, including a discussion of the technology. It also addresses key steps in the development of a successful biomass gasification project, including:

- Technology Assessment
- Site Selection Issues
- Environmental and Permitting Requirements
- Economic Feasibility and Financing

7.1 BACKGROUND

Gasification is an emerging technology that provides a way to transform solid biomass feedstocks into a combustible gas. The process of gasification involves heating biomass at extremely high temperatures, but with insufficient oxygen to allow complete combustion of the fuel. Under these conditions, the biomass solids break down to form synthesis gas, or syngas (producer gas, a related product, is created using a similar process, but at lower temperatures). When these volatile fuel vapors are extracted from biomass, solids, such as ash and other small particulates, are left behind (see Gasification Process Primer, below, and Figure 8). The syngas can be cooled, cleaned, filtered, and then burned in a gas turbine, gas reciprocating engine, or steam turbine. Syngas could potentially be used in a fuel cell as well, but this would require a costly gas purification system to ensure reliable fuel cell operation.

The New York State RPS recognizes gasification as a method for processing adulterated biomass feedstocks into clean fuels. Adulterated biomass feedstocks are materials derived from woody or herbaceous biomass where a treatment or coating has been applied; and animal byproducts and wastes. Feedstocks in this category include landfill biomass, animal manures, source-separated waste wood, and biomass from mixed waste. These feedstocks must undergo primary fuel conversion to biogas or biofuels before undergoing energy conversion. For more information, see Chapter 1 – Crosscutting Issues: Environmental Regulations and permitting. Also see the RPS Biomass Guidebook, available online at http://www.nyserda.org/rps/RPS_Biomass_Guide.pdf.

While limited in the number of full-scale commercial installations, biomass gasification technologies have been used for thermal energy generation (primarily steam), electricity generation, mechanical power generation, and combined heat and power (CHP). Gasifiers offer a flexible option for thermal applications, as they can be integrated with existing gas fueled devices such as ovens, furnaces, boilers, etc., where biobased syngas may replace fossil fuels. Gasification technologies using biomass byproducts are popular in the pulp and paper industry where they improve chemical recovery and generate process steam and electricity at higher efficiencies and with lower capital costs than conventional technologies. In some cases, additional processing of the syngas may produce liquid fuels. Like other gaseous fuels, syngas gives greater control over combustion levels when compared to solid fuels, leading to more efficient and cleaner boiler operation.

Of the three biomass technologies considered in this guidebook, biomass gasification is the least deployed and commercially available technology. However, it has great potential, and is anticipated to have widespread applicability once adequately proven to those specifying equipment for industrial and large commercial energy users.

A 2004 study funded by the US Department of Energy and Oak Ridge National Laboratory examined the market for CHP using opportunity fuels. This study identified a market potential of over 100 GW of electricity from alternatively-fueled CHP (see Table 14).[36] The greatest potential in both thermal generation and electric capacity was attributed to possible biomass gasification applications.

Table 14. Results Summary of the 2004 Study Examining the Market for CHP Using Opportunity Fuels. Source: US DOE, Oak Ridge National Laboratory, and Resource Dynamics Corporation.

Fuel	Potential Thermal Output (Estimated Trillion BTU/yr)	Potential Electric Capacity (Estimated GW)
Anaerobic Digester Gas	240	9.0
Biomass Gas	2450	89.0
Coalbed Methane	15	0.5
Landfill Gas	82	3.0
Tire –Derived Fuel	40	1.5
Wellhead Gas	3	0.1
Wood (Harvested)	270	10.0
Wood Waste	220	8.0

The opportunity represented by such market potential studies is compelling. However, in order to realize the potential of alternative biomass fuels coupled with gasification technologies, developers must overcome design, siting, operational, and financing barriers.

[36] *Combined Heat and Power Market Potential for Opportunity Fuels*, Resource Dynamics Corporation, 2004. This study was funded by US DOE and ORNL. It can be found at http://www.eere.energy.gov/de/pdfs/chp_opportunityfuels.pdf.

Gasification Process Primer

Gasification converts carbonaceous materials, such as coal or biomass, into synthetic gas or syngas (a mixture of carbon monoxide and hydrogen), by reacting the raw material at high temperatures with a controlled amount of oxygen and/or steam. Gasification can be applied to many different types of organic materials.

The advantage of gasification is that the syngas can be combusted more efficiently than direct combustion of the original fuel because it can be combusted at higher temperatures, so that the thermodynamic upper limit to the efficiency (defined by Carnot efficiency) is higher. Syngas may be burned directly in internal combustion engines, used to produce hydrogen or methanol, or converted (via the Fischer-Tropsch process) into synthetic liquid fuels.

Gasification of fossil fuel is currently used on industrial scales to generate electricity. However, almost any type of organic material can be used as the feedstock for gasification. Gasification can also begin with materials that are not otherwise useful fuels for direct combustion, such as organic waste. The high-temperature combustion refines corrosive elements such as chloride and potassium, leaving them in the ash and allowing clean gas production from otherwise problematic fuels.

Gasification relies on chemical processes at elevated temperatures >700°C, which distinguishes it from biological processes such as anaerobic digestion that produce biogas.

In a gasifier, the carbonaceous material is first dried to achieve the desired moisture content. It then undergoes several different processes:

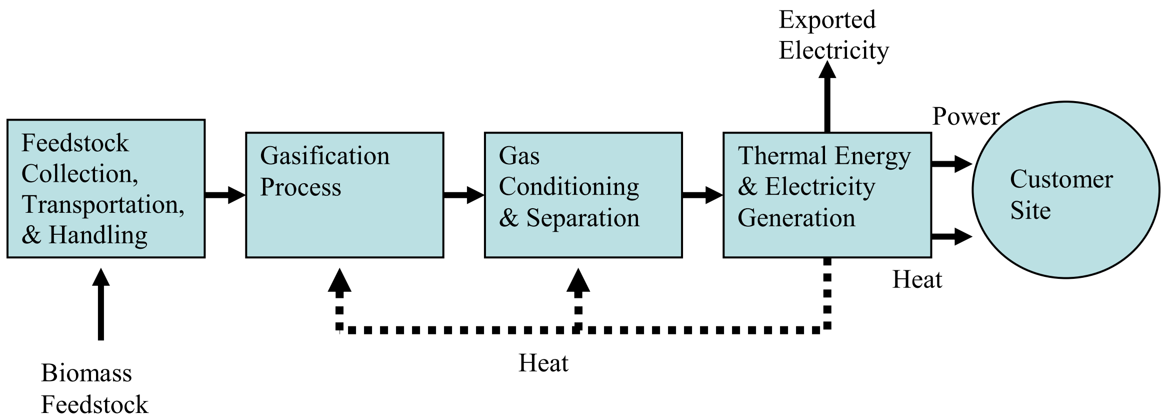
1. **Pyrolysis.** The *pyrolysis* process occurs as the carbonaceous particle heats up. Volatiles are released and char is produced. The process is dependent on the properties of the carbonaceous material and determines the structure and composition of the char. Biomass fuels are an ideal choice for pyrolysis because they have so many volatile components (70% to 85% on dry basis, compared to 30% for coal).

2. **Combustion.** Possible intermediate *combustion* processes may occur as the volatile products and some of the char reacts with oxygen to form carbon dioxide and carbon monoxide, providing heat for the subsequent gasification reactions.

3. **Gasification.** The *gasification* process occurs as the char reacts with carbon dioxide and steam to produce carbon monoxide and hydrogen. In addition, the reversible gas phase water gas shift reaction reaches equilibrium very fast at the temperatures in a gasifier. This balances the concentrations of carbon monoxide, steam, carbon dioxide and hydrogen. The primary categories of gasification are partial oxidation or indirect heating.

In essence, a limited amount of oxygen or air is introduced into the reactor to allow some of the organic material to be "burned" to produce carbon monoxide and energy, which drives a second reaction that converts further organic material to hydrogen and additional carbon dioxide.

Figure 8. The Gasification Process.



Many aspects of a biomass gasification project are similar to the other biomass technologies covered in this guidebook. Such crosscutting issues as fuel and feedstocks, environmental and permitting requirements, project financing and power offtake are covered in Chapters 1, 2 and 3 of this guidebook. However, there are a number of issues specific to biomass gasification. This chapter addresses these technology-specific issues.

7.2 TECHNOLOGY DEVELOPMENT AND COMMERCIALIZATION

Biomass gas is not yet widely used as an energy source because a cost-effective, efficient gasifier that produces high-quality gas has yet to be produced. The capital cost for gasifiers is too high, but several companies are working to change that. Near-term applications would generate power using a steam turbine in a stand-alone operation, or provide supplemental steam or combustion gas at an existing power plant.

Several existing companies would be capable of installing and servicing systems in New York if market conditions encouraged gasification installations. However, using gas turbines and combined-cycle plant layouts is currently considered higher-risk than a traditional power plant because of the market's limited experience with the technology. Before any advanced gasification installations could occur, performance guarantees and warrantees would need to be in place. While no companies in New York have yet provided these vital securities, there are some currently working toward that goal. Several companies are interested in testing the technology, although to date none have done so on a commercial scale in New York.

One major player in this field is Taylor Recycling in Montgomery, New York. Taylor Recycling's affiliate Taylor Biomass Energy has been working on a proprietary indirect fluidized gasification system project for several years. The originally proposed project was a 300 dry tons-per-day facility designed to use product gas in a steam boiler system with an electric generation output capacity of 11.5 MW. The site design was changed to accommodate a combined cycle generating facility that includes not only a steam turbine generator but also a combustion turbine generator. With these changes, the overall efficiency of the system improved to the point that the power island has a gross output rating of approximately 24 MW.[37] When completed, the Taylor Recycling project will be the largest biomass gasification installation in New York State (Taylor, 2009).

[37] A decision was made to replace the gasification process that had been investigated with a process developed by Taylor Biomass Energy. This new process incorporated a gas conditioning reactor to improve the product gas stream by reducing the condensable tars by 90% and in the process, raise the hydrogen content in the gas to approximately 45%. Due to the increase in hydrogen, the heating value of the conditioned gas decreased from 450 Btu/scf to 375 Btu/scf, however the volume of gas produced increased and as a consequence the energy content production rate remained constant at approximately 133 dth/hour.

7.3 NEW YORK STATE MARKET/PROJECT EXPERIENCE

There are limited numbers of gasifiers in operation in the U.S. Most of the biomass gasifiers use mill and crop residues as fuel. Of the non-biomass (fossil fuel) gasification applications, most are either large combined cycle turbine demonstration projects operating on coal (usually possible only through substantial government support), or small heating applications with crude gasification systems. Coal-fed combined cycle gasifier applications over 50 MW have had some success, but they are generally too expensive for smaller industrial applications. Some notable gasification projects have recently been announced by Johnson Controls, a major energy service company.[38] However, those installations will be limited to boiler/steam turbine configurations.

The two biggest hindrances to gasifier commercialization in the U.S. are the high capital costs of gasifier systems, and the lack of performance and reliability guarantees for gas turbines and engines operating on syngas. In addition, syngas presents energy content and gas clean-up issues. Several manufacturers of gas reciprocating engines, such as Caterpillar and Waukesha, have used landfill and digester gas, but have not yet used syngas in the U.S., although wood-derived syngas has been demonstrated in gas reciprocating engines by GE Jenbacher at several European installations.

As new gasification systems are developed and installed, efficiencies should continue to increase, costs should be driven down, and technical risks will be addressed and mitigated. State and local government initiatives, and the rising cost of fossil fuels, will also contribute to the development of future biomass gasification applications.

If implemented, the Taylor project described above would be a significant milestone in the commercialization of biomass gasification projects.

7.4 TECHNOLOGY STATUS: COMMERCIAL MATURITY AND NEW DEVELOPMENTS

7.4.1 Commercial Maturity

Compared with direct and co-fired biomass systems, gasification is not yet an established commercial technology, but there is great interest in the development and demonstration of gasification. One reason is that a gaseous fuel is more versatile than a solid fuel, as it can be used in boilers, process heaters, turbines, engines and fuel cells, distributed in pipelines, and blended with natural gas or other gaseous fuels.

Some gasification technologies using biomass and black liquor have developed to the point of large-scale demonstration. However, gasifier systems have not reached widespread commercial availability for systems suitable for integration with hydrogen separation technologies for fuel cells or fuel synthesis. This is due in part to areas of fuel chemistry that are not established enough to support commercial demonstration programs and facilitate the development and scale-up of advanced gasifiers and gas cleanup systems. However, it should be noted that the Taylor Recycling project has been redesigned to use Solar Turbine gas turbines in a combined cycle configuration for much greater electricity production than originally planned.

With respect to engine-based systems in the size range covered in this guide, Nexterra has announced a partnership with GE Jenbacher to offer equipment configured for CHP plants in the 2-10 MW range that

[38] Johnson Controls (JCI) has announced a partnership with Nexterra for developing projects that use Nexterra's fixed bed updraft gasifier. JCI/Nexterra installed a gasification system at the University of South Carolina. The resulting fuel is used in a combined heat and power system that creates 1.38 MW of electric power. The gasifier runs on wood residue with a moisture content of 25-55%. JCI, in an Energy Service Performance Contract with DOE, has plans to install a gasifier from Nexterra at Oak Ridge National Laboratory. The syngas produced by the gasifier will be coupled with a DOE-supported Super Boiler to provide 60,000 lbs/hr of steam to fulfill the lab's thermal needs. The fuel is wood residue with a moisture content of 10-50%. It is scheduled to be operational by late 2009.

use a Nexterra gasifier and a GE Jenbacher engine to produce power and heat at 60% efficiency. Nexterra is offering its gasifier technology only and not a turnkey package. The integration with other key components (e.g., fuel handling and treatment), the facility and the electrical grid is not offered. The system integrator role must therefore fall to the project developer, engineering procurement and construction, or host energy consumer organizations. These entities often perceive too much risk in using gasifier technology beyond the proven steam generation application. To overcome this perception of risk, project developers and engineering procurement and construction firms are in need of demonstration data on sustained integrated performance that meets technical, environmental, and safety requirements at a sufficiently large scale. Such demonstration data is essential to support gasification commercialization.

Biomass gasification research and development is continuing in several key areas:

- Feed Pretreatment
- Gasification
- Gas Cleanup and Conditioning
- Syngas Utilization
- Process Integration
- Sensors and Controls

7.4.2 Recent Developments

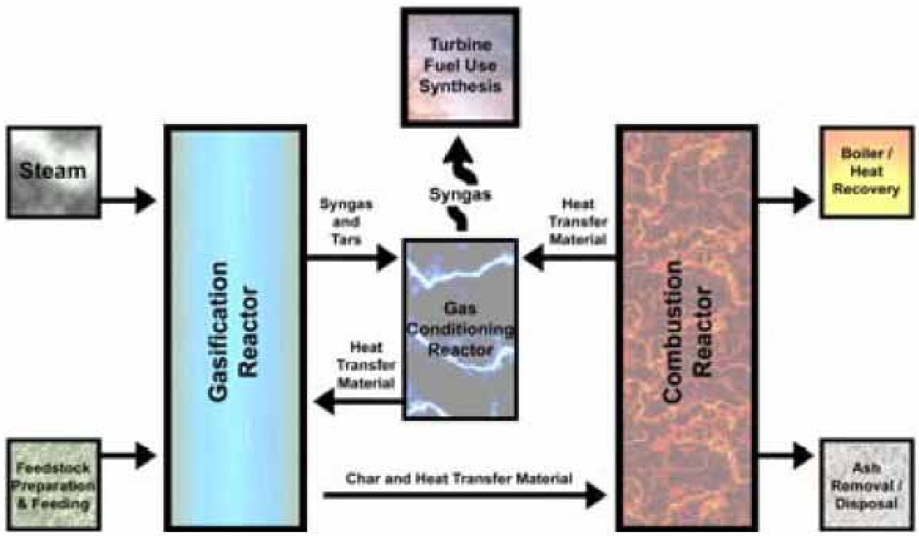
This section summarizes two biomass gasification technologies that have made recent advances in commercialization in the U.S. These projects offer many lessons learned, both for developers of biomass projects and for permitting agencies, with respect to feedstock assessment, RPS eligibility, environmental compliance and technology scaling for projects in the size range (<10 MW) considered in this guidebook.

Taylor Recycling

The Taylor gasification technology is an indirectly-fired circulating fluidized bed gasifier. It is based on knowledge gained at a pilot scale system built by FERCO at the McNeil Plant in Burlington, VT. The technology strategy has been to build off of the success of the DOE-supported FERCO technology, expand the range of possible feedstocks, and broaden the system design so that it works not just with boiler/steam turbines, but also with other practically available generating equipment, such as gas turbines (see Figure 9).

The Taylor project takes a novel approach to addressing the concentration of contaminants contained in the synthesis gas produced. This has been a significant limitation to the widespread use of biomass gasification for power or synthesis applications. The contaminants consist, primarily, of condensable hydrocarbons (tars) that restrict heat recovery from the gases and cause fouling of downstream equipment. Previously, the most prevalent solution to this has been to limit the use of the hot syngas in boilers or other similar direct combustion devices. However, this restricts the potential efficiency of such systems and virtually eliminates both the use of high efficiency power production via gas turbines, and the use of the gas for synthesis. To avoid these drawbacks, Taylor has developed an advanced, indirectly heated gasification process that effectively converts the tars in the gas to non-condensable, lower molecular weight species. This allows a higher level of the sensible energy contained in the synthesis gas to be recovered while simplifying any secondary conditioning of the gas that might be necessary.

Figure 9. Taylor Gasification Process. Source: Taylor Biomass Energy, LLC.



In the gasifier, biomass is contacted only by the heat carrying material, and steam. No air or oxygen is added so there are no combustion reactions taking place, providing environmental advantages. The biomass is rapidly (in less than one second) converted into medium calorific value gas (14-17 MJ/Nm^3) at a temperature of approximately 850°C. Any unconverted material, along with the cooled heat transfer material, passes through the gasifier and is separated from the product gas. The product gas continues to the gas conditioning step prior to any final gas cleanup that might be needed, while the solids are conveyed into the process combustion reactor.

In the combustion reactor, air is introduced. This consumes the char and, in the process, reheats the sand to approximately 1000°C. In the combustion reactor all remaining carbon is consumed, resulting in a carbon-free ash. Due to the combustion conditions and the fact that the unconverted material is essentially carbon, emissions are low from this step in the process. The reheated solids are separated from the flue gas and returned to the gasification reactor. Ash is removed from the flue gas, resulting in a high temperature (1000°C) clean gas stream, available for heat recovery.

The gas conditioning reactor is the key element of the Taylor Process that provides enhanced gas compositions along with the improved heat recovery potential. Within the gas conditioning reactor, the product gas contacts the high temperature solids (1000°C) providing an optimum environment for steam reforming of the tars. The tars are converted to lower molecular weight compounds that augment the quantity of synthesis gas produced.

The additional residence time provided by the gas conditioning reactor in the presence of a catalytic medium (the hot circulating solids) allows the synthesis gas to reach water gas shift equilibrium. As a result the hydrogen content of the synthesis gas is enhanced compared to other biomass gasification processes (Taylor, 2009).

Nexterra

Nexterra's gasification technology is intended to provide a clean, versatile and low cost means of converting wood and other solid fuels into syngas to produce heat and power at plant-scale applications. Nexterra initially developed gasification systems to displace natural gas at saw mills, panel board plants, pulp and paper mills, and institutional facilities using wood fuel. Future applications include next generation systems that are capable of operating on coal and other low cost fuels.

Nexterra's technology is a fixed-bed, updraft gasifier. Fuel, sized to three inches or less, is bottom-fed into the center of the dome-shaped, refractory lined gasifier. Combustion air, steam and/or oxygen are introduced into the base of the fuel pile. As fuel enters the gasifier, it moves through progressive stages of drying, pyrolysis, gasification and reduction to ash. Combustion air (20 - 30% of stoichiometric), steam and/or oxygen are introduced through the inner and outer cone into the base of the fuel pile. Partial oxidation, pyrolysis and gasification occur at 1500 — 1800 °F, and the fuel is converted into syngas and non-combustible ash. The process is maintained by simultaneous control of combustion air and fuel feed rate. Combustion temperatures in the fuel pile are tightly controlled and kept below the ash melting temperatures to ensure that there is no formation of "clinker" and that the ash flows freely. The ash migrates to the base of the gasifier and is removed intermittently through an automated in-floor ash grate. Syngas exits the gasifier at 500 — 700°F. The syngas can be combusted in a close coupled oxidizer with the resulting flue gas directed to heat recovery equipment such as boilers, thermal oil heaters, air-to-air heat exchangers, and turbines. A diagram of this system is shown in Figure 10.

Nexterra is also developing systems to directly fire syngas in industrial boilers, kilns, dryers and other equipment.

Figure 10. Nexterra Fixed-Bed Updraft Gasifier. Source: Nexterra.

Nexterra has partnered with Johnson Controls, an energy services company, and GE Jenbacher, a gas reciprocating engine manufacturer. In partnership with Johnson Controls, Nexterra has been awarded biomass gasification projects at the University of South Carolina (1.4 MW CHP plant fueled by wood residue, now in operation) and US DOE's Oak Ridge National Laboratory (coupled with the DOE funded Cleaver-Brooks Super Boiler, Nexterra's gasifier will produce 60,000 lb/hr of saturated steam and displace fossil fuels currently in use). Nexterra has also announced that its biomass gasification system at Dockside Green is now operational and providing heat and hot water to residents of a green development in Victoria, British Columbia. In addition, it was recently announced that the University of Northern British Columbia will install a Nexterra biomass gasification system to heat its Prince George campus.

7.5 ENVIRONMENTAL/PERMITTING ISSUES

Biomass gas, when produced in an efficient, state-of-the-art gasifier, burns as cleanly as natural gas. Emissions from biomass gas combustion include SO_2 and NO_x particulates, Hg, CO, and CO_2. The types of particulates and contaminants present in biomass gas will depend on the quality and type of gasifier used, and the feedstock. Some types of biomass, especially when used in certain types of gasifier systems, produce a great deal of tar that must be removed.

Generally, biomass gasification emissions levels are similar to those from conventional natural gas turbine facilities and slightly higher than those from natural gas combined-cycle applications. They are substantially lower than those from coal-fired power plants, co-firing applications, and direct-fire biopower applications. Mercury emissions from the combustion of gasified biomass are low compared to coal combustion.[39] Life cycle greenhouse gas emissions from the combustion of gasified biomass are either small or negative, depending upon the biomass resource used. See Chapter 1 - Crosscutting Issues: Environmental Regulations and Permitting, and appendices for more information on emissions and permitting requirements.

7.6 TECHNOLOGY ASSESSMENT

7.6.1 Energy Conversion

In electricity generation and CHP applications, gasifiers can be integrated with boiler/steam turbines, gas turbines, and spark-ignited gas reciprocating engines.

Firing in Boilers or Heat Applications

Firing the raw gas in boilers or heat applications, such as kilns after removal of dust and particulates, is the simplest application since the gas is kept hot and the tar problem is avoided. This market is one where all types of gasifiers can compete. For these applications, low tar content is not essential if the wall temperature of the gas pipe system can be maintained above the level where tars condense.

Gas Turbine Operation

Gas turbines operate at very high temperatures, up to 850° C. Some of the compounds formed from ash forming elements in the biomass exit the gasifier in a gaseous or liquid state. Also, at low concentrations of such compounds in the hot gas entering the turbine, severe deposition and corrosion (for instance on turbine blades) can be expected. Possible solutions to this problem include operation of the gas turbine at low inlet temperature, gas cleaning for removal of the troublesome compounds or gasification under conditions where the formation of these compounds is minimized.

[39] US Environmental Protection Agency, AP 42, Fifth Edition - Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, and US EPA eGRID

Engine Operation

For engine operation, the dust content in the gas should be as low as possible. Spark ignition engines can be operated on 100% producer gas. Compression engines (diesel engines) require at least 10-20% diesel oil to bring about ignition of the gas. In both cases a down-rating of the engine should be expected.

Neither engines nor turbines can tolerate tar in the gas, although work is ongoing to develop more tolerant engines. Thus, it is the responsibility of the gasification operator to deliver clean gas.

Conditioning and cleanup of the syngas will likely be required for reliable operation with the suite of generation prime movers in the <10 MW size range. Prime movers have been operated using some medium heating value biogas, but there is not much collective experience with this fuel. Many equipment providers will not guarantee performance, emissions, or reliability of their equipment if it is run on gasified biomass fuel. Operation on low heating value biogas and the effects of impurities on prime mover reliability and longevity need to be demonstrated before commercial guarantees are offered as a normal course of business. Until that is the case, it can be expected that the majority of biomass gasification projects will continue to be for thermal energy/steam generation.[40]

7.6.2 Gasifier Types

Two principal types of gasifiers have emerged: fixed bed and fluidized bed. Fixed bed gasifiers are typically simpler, less expensive, and produce a lower heat content syngas. Fluidized bed gasifiers are more complicated, more expensive, and produce a syngas with a higher heating value. Within those types, there are further distinguishable biomass gasifier types. Each has its own set of advantages and disadvantages. The basic types are listed below:

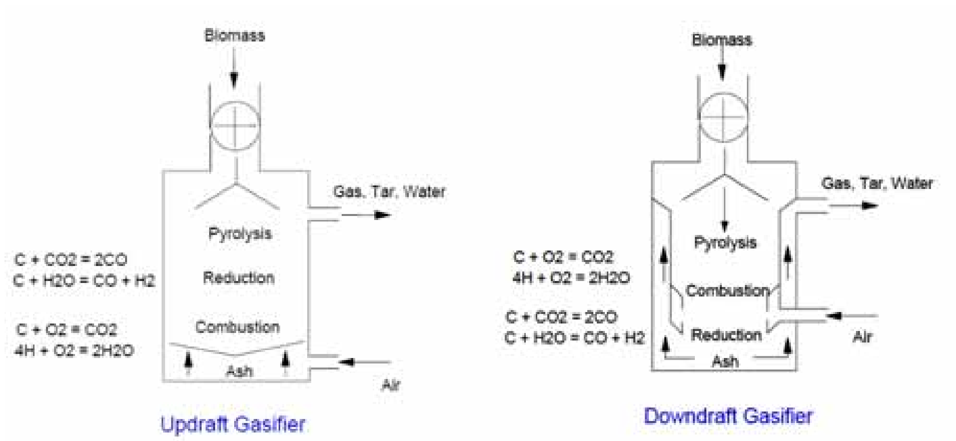
- Updraft Fixed Bed
- Downdraft Fixed Bed
- Bubbling Fluidized Bed
- Circulating Fluidized Bed
- Entrained Flow Fluidized Bed

Each type has advantages and disadvantages, which are identified in Table 15. Diagrams of several of the more common types of gasifiers are shown in Figure 11.

[40] This points to a potential role of support for both NYSERDA and the US DOE. Since the gas turbine and gas reciprocating engine markets are driven by natural gas as the primary fuel source, there is justifiable concern about the future availability of gas turbines and gas engines for gasification applications; it will be important to keep prime mover combustion and control system development in sync with developments in the gasification and biomass industries.

Figure 11. Gasification Pathways. Source: National Renewable Energy Laboratory.

Fixed Bed



Fluidized Bed

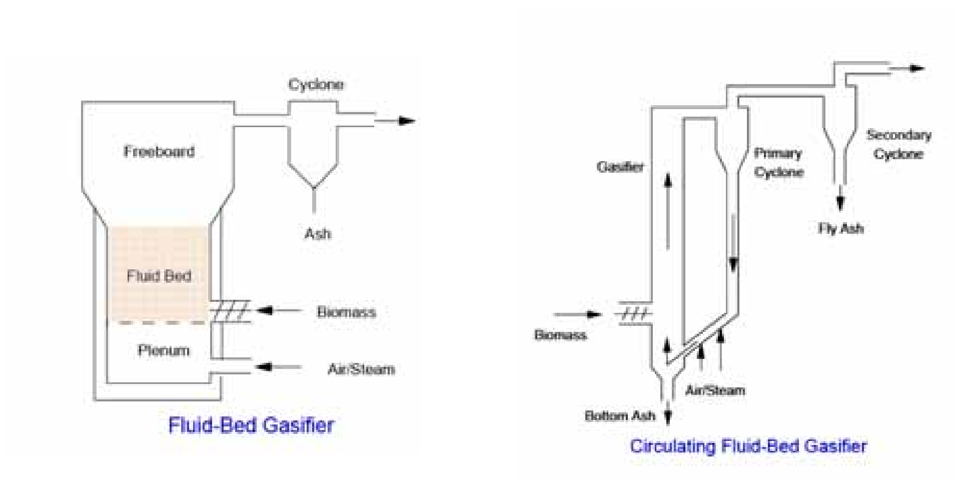


Table 15. Advantages and Disadvantages by Gasifier Type.

Gasifier Type	Advantages	Disadvantages
Fixed Bed - Mostly for small scale applications. Fixed-bed gasifiers typically have a fixed grate inside a refractory-lined shaft. The fresh biomass fuel is placed on top of the pile of fuel, char, and ash inside the gasifier. Fixed-bed gasifiers come in Updraft and Downdraft types.		
Updraft - Biomass is introduced from the top and moves downward. Oxidizer (air) is introduced at the top and flows downward. Syngas is extracted at the bottom at grate level.	• Mature for heat • Small scale applications • Can handle high moisture • No carbon in ash	• Feed size limits • High tar yields • Scale limitations • Producer gas • Slagging potential
Down Draft - Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows upward. Some drying occurs. Syngas is extracted at the top.	• Small scale applications • Low particulates • Low tar	• Feed size limits • Scale limitations • Producer gas • Moisture sensitive
Fluidized Bed - The primary gasification process takes place in a bed of hot inert materials suspended by an upward motion of oxygen-deprived gas. As the amount of gas is augmented to achieve greater throughput, the bed will begin to levitate and become "fluidized." Fluidized bed gasifiers can be designed to use a portion of the pyrolysis gases to generate the heat to drive the process, or they can be externally fired. Sand or alumina is often used to further improve the heat transfer. Notable benefits of fluidized bed devices are their high productivity (per area of bed) and flexibility. Fluidized bed gasifiers can also handle a wider range of biomass feedstocks with moisture contents up to 30% on average. Fluidized bed gasifiers come in Bubbling, Circulating and Entrained Flow types.		
Bubbling - At the lower end of fluidization, the bed expands and begins to act as a fluid. As the velocity is increased, the bed will begin to "bubble."	• Large scale applications • Feed characteristics Direct/indirect heating • Can produce syngas	• Medium tar yield • Higher particle loading
Circulating - With a further increase in airflow, the bed material begins to lift off the bed. This material is typically separated in a cyclone and "recirculated" to the bed.	• Large scale applications • Feed characteristics • Can produce syngas	• Medium tar yield • Higher particle loading
Entrained Flow - With still higher velocities, the bed material is entrained (i.e., picked up and carried off in the airflow).	• Can be scaled • Potential for low tar • Can produce syngas	• Large amount of carrier gas • Higher particle loading • Particle size limits

The vast majority of manufacturers with commercial products offer fixed bed downdraft designs. Approximately 20% of the designs are fluidized bed systems. For large scale applications, the preferred and most reliable system is the circulating fluidized bed gasifier. For small scale applications, downdraft gasifiers are preferred.

There is still a considerable amount of development activity underway to address technical barriers and operational issues (See Table 16).

Table 16. Technical Barriers and Operational Issues.

Hydrogen Separation	Some gasification technologies using biomass and black liquor have developed to the point of large-scale demonstration. However, gasifier systems have not reached widespread commercial availability for systems suitable for integration with hydrogen separation technologies for fuel cells or fuel synthesis. This is due in part to areas of fuel chemistry that are not established enough to support the commercial demonstration programs and facilitate the development and scale-up of advanced gasifiers and gas cleanup systems.
Syngas Cleanup and Conditioning	The raw gases from biomass systems do not currently meet strict quality standards for downstream fuel, chemical synthesis catalysts, or those for some power technologies. These gases require cleaning and conditioning to remove contaminants such as tar, particulates, alkali, ammonia, chlorine, and sulfur. Available cleanup technologies do not yet meet the needed cost, performance, or environmental criteria needed to achieve commercial implementation.
Sensors and Controls	Development of effective process controls is needed to maintain plant performance and emissions at target levels with varying load, fuel properties, and atmospheric conditions. New sensors and analytical instruments are under development to optimize control systems for thermochemical systems.
Process Integration	As with all new process technologies, demonstrating sustained integrated performance that meets technical, environmental, and safety requirements at a sufficiently large scale is essential to supporting commercialization. Applications such as black liquor integration in paper mills have the added complexity of being attached to an existing commercial process where the unit operations associated with steam production, power, pulping, and chemical recovery must all be integrated.
Containment (materials of construction)	Experience with existing gasifiers indicates that gasification reactions are difficult to contain. Development of materials for reactor shells and internals, refractory materials to line containment vessels, vessel design, and increased knowledge of bed behavior and agglomeration should improve performance over the long term.

7.7 SITE SELECTION ISSUES

This section focuses on site selection and integration issues specific to biomass gasification. Site selection issues relevant to biomass projects in general are covered in Chapter 1 – Crosscutting Issues: Environmental Regulations and Permitting.

There have been a very limited number of actual commercial installations of biomass gasification systems in New York State and the United States on which to develop a clear set of industry "best practices." However, it is clear, based on the experience of gasification technology providers, project developers, engineering firms, and energy users who have considered biomass gasification, that successful integration of the project with the site is the primary goal and challenge of site assessment/selection. Successful integration results in both economically and technically viable projects.

Site selection for biomass gasification projects should be undertaken with the understanding that a full State Environmental Quality Review (SEQR) and Storm Water Management Pollution Prevention Plan (SWPPP) will be required. These were the major permitting activities associated with the Taylor Recycling Project.

Because commercial site selection and permitting experience for biomass gasification projects is so limited, excerpts from the Taylor Recycling project permits are reproduced below. These give a good idea of the regulatory and permitting hurdles a project is likely to face.

Taylor Recycling SWPPP and Construction Activity General Permit Example

The Taylor Recycling site is served by a number of ponds. The ponds are so situated that through the use of ditches, piping, culverts the water produced during storms is directed to these ponds. These ponds will be expanded to create protected areas to comply with Corps of Engineer's requirements for wetland mitigation. The ponds take up a surface area of approximately three acres and are covered in the General Permit to construct under a specific Storm Water Pollution Prevention Plan (SWPPP). The General Permit sets forth the industry accepted best practices that must be followed during and after actual construction on site.

SWPPP was prepared in support of a Notice of Intent (NOI) for a SPDES Construction Activity General Permit. The NOI is submitted to the NYDEC. As covered in the NOI, the construction area on the 95 acres of property includes approximately seven acres.

The application requires the following information:

- Site coordinates using the DEC interactive map.
- Nature of the construction.
- Existing and post land use (residential, commercial, industrial…).
- Whether the property is used for any agricultural purposes, is a remediation site, or has state ownership.
- How many acres will be disturbed and the types of soil present on the site.
- Duration of construction.
- Tributaries into which the water flows.
- Existing systems into which the water may enter.
- May the storm water enter a combined sewer?
- DEC authorized Erosion and Sedimentation Control by DEC Blue Book.
- In conformance with the DEC design manual, a listing of Post Construction Storm Water Management Practices.
- A listing of all the erosion control and sedimentation control practices used on the site
- Specific details on storm water management practices
- A listing of pre and post construction impervious areas
- A listing of all the post construction storm water control devices installed
- Storm water discharge points from the site
- Other DEC permits that will be required as part of the construction.

Taylor Recycling – Qualifying Gasified MSW in NYS RPS

The proposed project was qualified under the New York State Renewable Portfolio Standard (RPS) for sorted and separated biomass from various sources of fuel such as Construction and Demolition (C&D) material as well as Mixed Solid Waste (MSW). Qualification requires sorting and separating along with gasification with emissions that are less than or equal to [those from] unadulterated biomass.

In regard to this qualifying standard, Taylor collected over a thousand pounds of MSW from the Orange County New Hampton Transfer Station in Goshen. This material was sorted and separated. The biomass portion was sent to Toll Manufacturing in New Jersey for pelletizing. The pelletized material was then sent to the National Renewable Energy Laboratory (NREL) in Golden Colorado for Toxicity Characteristic Leaching Procedure (TCLP) and gasification process testing. These tests took place in NREL's pilot scale gasifier, which was configured to accurately simulate the operational characteristics of the Taylor gasifier. Tests for material received indicated that the gasifier would produce medium calorific gas capable of being compressed for direct injection into a combustion turbine. Ash recovered after the testing was subjected to TCLP testing and results showed no component approaching regulatory standard limits.

Eighty-seven percent of the MSW received from Orange County could be used in the gasification process. However, almost 20% of this 87% are plastics or plastic based materials. Most concerning is the fact that such material, even if not accounted for in the production of renewable energy, may not be part of the fuel mix to qualify under the RPS. Thus a substantial proportion of the material coming in will need to be excluded if the fuel is to qualify under the NYS RPS.

The material tested at NREL had an actual Btu content per pound of 7,870 as tested. By weight of the material, the plastics, textiles, and styrofoam made up 20% of the material that could be used in the gasifier. This plastics based material is very high in Btu content with an estimated value of 18,000 Btu/pound. Remaining material without the plastics had a Btu content of 5338 Btu/pound. Thus by weight 20% of the material coming from plastics provided 46% of the heating value, so eliminating plastic material from the MSW would produce a significant reduction in the heating value of the fuel.

An evaluation is needed to determine whether the additional MSW to fuel the gasifier and sell RECs justifies eliminating the plastics in the fuel supply.

7.8 ECONOMIC FEASIBILITY AND PROJECT FINANCING

Financing is a key part of the entire project development process. In most respects, financing a biomass gasification project is similar to financing other biomass projects. However, developers of gasification projects should be aware that financiers may well assign greater risk to a technology that is both capital intensive and not fully commercialized.

For a detailed discussion of the financing process, see Chapter 2 – Crosscutting Issues: Financing. A financial case study is presented in Appendix 3.

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APPENDIX A: ENVIRONMENTAL COMPLIANCE

This Appendix summarizes the environmental impact characteristics of small to medium scale applications of the three biomass technologies addressed by this Guidebook; and it addresses the environmental review framework in place for all such projects in the State of New York.

Agricultural digesters

In New York, at this writing, there are at least 16 farms using agricultural digesters. The plug-flow type is most prevalent, but there are also several other types in use, including complete mix and hybrid systems (mixed and plug-flow).

Anaerobic digestion results in a reduction of volatile solids, fixed solids, chemical oxygen demand, soluble chemical oxygen demand, volatile acids, Kjeldahl nitrogen, organic nitrogen, and phosphorus. The effluent from agricultural digesters can be used as animal bedding or fertilizer to further reduce its environmental impact. Specifically, the effluent can be spread in warmer months when the fields are dryer and nutrient uptake is at its maximum. This will improve water quality, because the nutrients are in their organic forms and can easily be taken up by plants resulting in less runoff (Wright, 2001).

GHG air emissions are significantly reduced by agricultural digestion. Depending on the type of digester, methane may be reduced by as much as 12.87CO_2e T/animal/yr.

Digesters may also help control water pollution. Pathogens including fecal coliforms, fecal streptococcus, and *M. avium paratuberculosis* have been shown to be significantly reduced when digesters are used as part of a manure management system. Oxygen demand has also been show to be reduced. This lessens the depletion of dissolved oxygen in surrounding waters.

Agricultural digesters can also reduce manure odors, by up to 97%.

Although beneficial in many respects, the effluent from agricultural digesters has been shown to result in an increase in ammonia nitrogen, which increases water toxicity. Another concern is the release of volatilized ammonia into the air; to ensure that this is kept to a minimum, the crust over any manure storage lagoons should be well maintained.

There can also be safety issues associated with agricultural digesters. Biogas is highly corrosive and flammable. To prevent safety hazards the biogas storage and use system needs to be constructed according to standard engineering practices for handling a flammable gas (Natural Resources Conservation Service Conservation Practice Standard 2005). Another potential problem is human exposure to H_2S, which can be fatal. However this problem can easily be mitigated by ensuring that plant operators have proper H_2S hazard training (Martin, 2008).

The environmental impacts of agricultural digesters are summarized in Table 17.

Table 17. Environmental impacts of an agriculture digester facility.

Environmental Characteristic	Impact		Environmental Footprint			Level of Significance	Possible Mitigation of Impacts	Additional Notes
Solid Waste Emissions	Digester performance (% reduction from influent to effluent)	Digester Type	Farm A: Plug-flow	Farm B: Covered Lagoon	Farm C: Mesophilic intermittently mixed			
		Total Solids	21.5	21.7	35.4			
		Total volatile solids	29.7	26.3	39.6	Reduction in total volatile solids, chemical oxygen demand and volatile acids causes reduction in odor		
		Fixed solids	nsd	16.5	31.1	-	Mitigation of solid waste from digester through its application as a fertilizer or as animal bedding.	Nutrients are released from their organic state and are much more readily available to plants during the growing season, initially as ammonia but quickly converted to soluble nitrate. The filtrate, being less viscous, does not stick to leaves and does not suppress plant respiration
		Chemical oxygen demand	41.9	26.8	38.5	Reduction in total volatile solids, chemical oxygen demand and volatile acids causes reduction in odor		
		Soluble chemical oxygen demand	30	28.1	58.8	-		
		Total volatile acids	86.1	74.0	87.8	Reduction in total volatile solids, chemical oxygen demand and volatile acids causes reduction in odor		
		Total Kjeldahl nitrogen	nsd	nsd	nsd	-		
		Organic nitrogen	nsd	nsd	36.3	-		

		Ammonia nitrogen	+ 33.4	nsd	+ 24.9	Increases water toxicity		
		Total phosphorus	nsd	nsd	nsd	-		
		Orthophosphate phosphorus	+ 23.0	nsd	64.4	-		
	Air Emission (reduction due to use of digester)	CH_4 (CO_2e T /animal/yr)	3.03	12.06 - 12.87	2.32 - 3.03	-	Maintaining a crust over the lagoon will minimize the loss of ammonia	
		H_2S (% volume of biogas)	0.193	0.0086	0.31	The amount of H_2S in biogas is proportional to the amount of SO_x released after biogas combustion		
		N_2O	-	-	-	-		
		NH_3	-	-	-	-		
Water Quality	Oxygen Demand (lbs/animal/day)		8.4	~9.75 - 10.4	5.1	A reduction in oxygen demand lessens the risk of depleted dissolved oxygen in surrounding water	-	-
	Pathogens (% reduction)	Fecal Coli-forms	~99.9	~90	~99.9	Reduced potential of contaminating surrounding water	-	-
		Fecal Strepto-coccus	-	~75	~90			
		M. avium paratuberculosis	~99	-	-			
	Nutrient Enrichment		-	-	-	No significant reduction in nutrient enrichment	-	-
Notes: (Farm A = 550 Dairy Cow Herd, Farm B = 1500 - 1600 Dairy Cow Herd (400-450 "dry"), Farm C = 750 to 860 Dairy Cow Herd)								
Data collected from EPA AgStar case studies: http://www.epa.gov/agstar/resources.html								

Table 18. Possible public opposition to the establishment of an agriculture digester facility.

Environmental Characteristic	Impact	Sub-Category	Level of Significance	Possible Mitigation of Impacts
Community	Public nuisance	Odor	Should significantly reduce odors from existing manure management operations	
		Noise	Plant processing noise as well as additional traffic noise, especially if food processing waste is trucked in	Compliance with local noise pollution levels; truck deliveries during business hours
		Vibration	Minimal	-
		Increased traffic	Increases in truck traffic can potentially damage roads and/or cause traffic safety concerns	-
	Resources	Demand on community services	Gas and electricity production can increase demand on some services, such as emergency/fire response services.	-
		Use of existing facilities	Can existing facilities be retrofitted to minimize impacts to community and environment?	Storage of seasonally-produced food wastes may be accomplished using existing silos or other buildings
	Quality of local area	Economy	Could potentially affect property values, tourism	-
		Aesthetics	The visual impact of the facility may be significant to the community. These aesthetic impacts can be quantified for a specific community but not for communities in general	Screening with trees, fences, existing facilities or geographical features; use of silos and other existing structures
		Future open spaces / recreational land	Fear of negative impacts to wildlife and ecosystems, aquatic environment and surrounding rural areas. Will the establishment of proposed facility set a precedent for further industrial development?	-
	Risk	Hazardous materials / Explosion	Fear of public health hazards, accidents.	Well ventilated buildings. Explosion proof motors, wiring and lights. Flame arrestors used on gas lines. Use of gas alarms and detectors
		Public Health and Safety	There may be long-term uncertainties about the general health impacts caused by the plant, such as increases in local air pollution, chemical runoff and water pollution.	-

Environmental characteristics of direct combustion and co-firing.

The environmental characteristics of direct combustion and co-firing can be broken into upstream processes associated with feedstock cultivation, collection and transportation; energy conversion processes; and waste disposal.

Facility air emissions from biomass energy conversion are generally significantly lower than those from coal fired power generation. Nevertheless these direct combustion technologies may pose significant environmental impact risks that do require careful attention to ensure that projects are sited, designed, constructed and operated to avoid significant adverse impacts.

If feedstocks are sourced from waste streams or sustainable, closed-loop energy crop systems, biomass can achieve a near net zero increase in atmospheric carbon dioxide over the life cycle of the fuel. Plant air emissions from co-firing contain significantly lower levels of SO_X compared to coal-only firing, with a linear decline as more coal is removed; consequently, emissions of SO_X from direct combustion can be minimal, assuming feedstock contains low concentrations of sulfur. Levels of PM_{10} emissions from biomass firing can be higher in some instances than from coal firing, depending on feedstock input; however, installation of a cyclone separating device can minimize this impact (Zhang, Habibi and MacLean 2007). Ash production is dependent on individual fuel properties, the type of combustion system used, and interactions between co-fired fuels (Robinson, et al. 1998). Uncontaminated ash can be returned to the soil as a low grade fertilizer; ash that contains high concentrations of heavy metals must be disposed of appropriately. Condensed steam contains minimal pollutants and is considered of minor environmental impact (Groscurth, Kuhn and al 1998).

Upstream processes associated with cultivation and transport of dedicated feedstocks, such as conversion of forest and grassland to farmland for dedicated energy crops, can release significant amounts of carbon trapped in the soil, creating a “carbon debt” that can be quite significant. However, the selection of appropriate feedstocks for cultivation can help minimize this impact. For example, replacing annual crops with perennial energy crops reduces soil disturbance and erosion (Brown, et al. n.d.). The use of waste materials for feedstocks can result in very attractive economic as well as environmental profiles for biomass power production. NYSERDA has identified wood and wood wastes as New York’s largest renewable and sustainable resource. Collecting wood residue directly from forested areas can lead to soil degradation through reduced nutrient recycling; collection of such material needs to be managed appropriately to mitigate this impact. In addition to directly reducing GHGs such as CO_2, NO_X and SO_X produced during energy production, the use of waste wood diverts material from landfills, lessening landfill decomposition and the release of CO_2 and CH_4 into the atmosphere.

In addition to air emissions, impacts to the local community can include noise pollution, aesthetic impacts and impacts associated with truck traffic related to supplying the plant with large volumes of biomass fuel and/or feedstocks. The lower energy density and rural origins of many biomass feedstocks implies that demands on transportation networks will increase with increased biomass use, consequently increasing the potential for traffic accidents and placing additional demands on local services.

Regardless of feedstock selection, when compared with coal, biomass direct combustion and co-firing present a more environmentally friendly alternative with significantly lower greenhouse gas emissions (see Table 19).

Table 19. Environmental Impacts of a direct combustion and co-firing facility.

Environ-mental Characteristic	Impact		Environmental Footprint			Level of Significance	Possible Mitigation of Impacts	Notes
Air	Facility Air Emissions		Coal Only	Direct biomass combustion (figures for stoker boiler and fluidized bed using wood residue)	Co-Firing (10%)		-	-
		CO	0.02 - 0.41	0.077 - 5.533	0.02 - 0.41	No appreciable difference in CO emissions		
		NMHC (non-methane hydrocarbons)	-	-	-	Appropriate selection of feedstock reduces NMHC emissions	Appropriate selection of feedstock	-
		NO_x (g/kWh)	1.46 - 2.59	0.408 - 0.95	1.31 - 2.33	Variable	Primary and secondary NO_x emission abatement equipment, low NO_x burners, advanced primary NO_x reduction techniques such as a two stage combustion and reburn technologies, selective non-catalytic NO_x reduction techniques and selective catalytic NO_x techniques.	NO_x emissions impact of biomass is variable and not easily quantified
		N_2O	-	-	-	Less easily quantified as biomass may contain similar N content as coal. For example, switchgrass contains 0.92lbs N per MMBtu comparable to coal N content of 0.93lbs N per MMBtu	-	-

		SO_x (g/kWh)	4.2 - 5.2	0.036	3.9 - 4.7	Assuming biomass with negligible sulfur concentrations, emission decline linearly as the coal fraction is reduced	Installation of wet limestone-gypsum flue gas desulphurization equipment.	Most biomass has nearly zero sulfur content. SO_x emission reductions occur on a one to one basis with the amount of coal offset
		VOC (g/kWh)	0.02	0.01	0.02	No appreciable difference in VOC emissions	-	-
		PM_{10} (g/kWh)	0.2	0.136 - 0.428	0.2	Increase in particulate emission in some circumstances, dependant on feedstock compared with coal only firing.	Bag house - cyclone separating device separates out particulates; can be retro-fitted to existing facilities.	-
	Upstream Emissions (based on a 10% co-firing rate)	CO (g/kWh)	0.05 - 0.26	-	0.06-0.25	Despite production of upstream emissions through cultivation and transport, life cycle environmental footprint for most emissions is still reduced comparable with coal (NO_x is an exception for non-residue biomass feedstocks; cropping systems can be NO_x intensive).	Radius of biomass collection generally limited to 50miles	
		NMHC (non-methane hydrocarbons)	-	-	-			
		NO_x (g/kWh)	0.45 - 0.79	-	0.45 - 0.75			
		SO_x (g/kWh)	0.1	-	0.1			
		VOC (g/kWh)	0.04 - 0.07	-	0.04 - 0.06			
		PM_{10} (g/kWh)	0.1 - 1.3	-	0.1 - 1.2			
Land	Agricultural land	Land Resource	-			Possibility that energy crop production will reduce food crop land	Use of conservation reserve program (CRP) land to grow dedicated energy crops; use of waste feedstocks	-
		Carbon Sequestration (by feedstock)	Short Rotation Woody Crop	Willow carbon sequestration (SOC) 296g m^{-2} yr^{-1}		Carbon sequestration dependant on specific crop type, farming practice, climate, soil conditions and soil carbon saturation. Ranges may vary from 36 - 710 g m^{-2} yr^{-1}	-	-
			Herbaceous Crop	Switchgrass carbon sequestration (SOC) 298g m^{-2} yr^{-1}				
			Forest Residue	Average carbon sequestration (SOC) 338g m^{-2} yr^{-1}				

		Herbicides and Pesticides (by feedstock)	Short Rotation Wood Crop	12 x less herbicides and 19 x less insecticides compared to corn production	Energy crops act as filter systems, removing pesticides and excess fertilizers from surface water before it polluted groundwater or streams/rivers.	-	-
			Herbaceous Crop (Switchgrass)	Equal amounts of herbicide compared to corn production. Insecticide is rarely used at all.			
		Fertilizers	Increased use of fertilizer (Potassium and Nitrogen)		Nutrient overload in surrounding areas	Short rotation coppice, miscanthus and other energy crops require lower fertilizer inputs than common agricultural crops. Recycling of nutrients by using ash waste from co-firing reduces the need for chemical inputs.	-
	Municipal Land	Existing Facilities	-		-	-	At co-firing rates above 5%, modifications to existing plants may be needed, such as fuel receiving and handling equipment. Biomass drying may also be necessary, depending on boiler configuration and the acceptable level of derating
		Landfills	CO2	73.8kg / 100Kg oven dried biomass	During landfill decomposition, wood waste releases roughly equal amounts of methane and CO_2. Combustion mitigates this impact.	Removal of wood waste from landfills.	-
			CH4	18.3Kg / 100Kg oven dried biomass			

	Solid Waste	Biomass Ash Deposition (g/Kg fuel)	Wood	0.04	Ash deposition rates not affected significantly when co-firing wood or similar low-ash, low alkali, low-chlorine fuels.	Use of low ash, low-alkali, low chlorine fuels	Deposition rates depend strongly on both individual fuel properties and interactions between the co-fired fuels
			Switchgrass	2			
			Straw	12	Ash deposition rates increase when co-firing high-chlorine, high alkali, high ash fuels such as herbaceous and agricultural residues		
			Wheat Straw	30			
		Coal Ash Deposition (g/Kg fuel)	Pittsburgh #8	2	-		
		Combined Ash	-		Co-fired ash does not meet ASTM standard (C618) and therefore cannot be used in cement manufacture	Use of ash as a byproduct dependant on content of organic and inorganic pollutants. Uses include low grade fertilizer, road construction and landscaping.	-
		Mercury and other heavy metals	Co-firing of sub-bituminous coal and high chlorine biomass (chicken waste) - 80% reduction in mercury		Mercury emissions strongly related to chlorine content of biomass. There is potential for reduced mercury, however, there is also risk of increased lead	Heavy metal emission can be avoided almost entirely by improved sorting of waste and good plant design (metals can be removed in the flue gas)	ASTM standards for concrete admixtures require 100% coal ash. Efforts are underway to demonstrate suitability of commingled biomass and coal ash in concrete admixtures, but in the near term, co-fired ash will not meet ASTM specifications.
			Co-firing of sub-bituminous coal and low chlorine biomass (wood pellets) - 50% reductions in mercury				
Water	Usage	Facility	-		-	-	Increase in water consumption considered negligible compared to coal-only operation

		Biomass Cultivation	Short Rotation Woody Crop (poplar)	42m3/GJ	Water use for cultivation and production of energy from biomass crops is 70-400 times larger than that required to create energy from a mix of non-renewable resources. This wide range is dependent on differences in crop characteristics, agriculture production conditions and climatic circumstance.	Average water use for bioenergy crops grown in the US is 58m3/GJ. Cultivation of perennial low input crops reduces need for water usage (switchgrass)	-
			Herbaceous Crop (Miscanthus)	37m3/GJ			
	Quality		-		Runoff during crop establishment could be comparable to or greater than that from annual row crops, especially for tree crops treated with herbicides to suppress competing vegetation.	-	It has been projected that displacing annual crops with perennial biomass crops would reduce runoff -- decreasing soil erosion and improving water quality.
	Liquid Waste	Sewage	-		-	-	-
		Industrial Waste	-		-	-	-

Table 20. Possible public opposition to the establishment of a Direct Combustion and Co-Firing Facility.

Environmental Characteristic	Impact	Sub Category	Level of Significance	Possible Mitigation of Impacts	Notes
Community	Public nuisance	Odor	Will plant emissions create undesirable odors?		
		Noise	Plant processing noise as well as additional traffic associated with the plant (fuel deliveries, waste removal)	Compliance with local noise pollution levels; appropriate scheduling of truck traffic	
		Vibration	Minimal	-	-
		Increased traffic	Increases in traffic movement and flow of high goods vehicles. Damage to road systems through increased heavy traffic, with possible additional expense to taxpayer.		
	Resources	Demand on community services	Demands (and thus costs) on local infrastructure facilities might increase with new or expanded facilities. If new facilities create economic opportunities resulting in increased population, this can put added pressure on infrastructure, at increased cost.		
		Use of existing facilities	Can existing facilities be retrofitted thus mitigating impact to community and environment?	Prior land use replaced by plantation. On degraded lands or excess agricultural lands. Plantations should never replace natural forests.	
	Quality of local area	Economy	Affects property prices, tourism and business		
		Aesthetics	If the facility is built in an undeveloped area, the visual impact of the facility may be significant to the community as may the potential plant or animal habitat loss. These facility-related effects can be quantified for a specific community but not for communities in general		
		Future open spaces / recreational land	Fear of negative impacts to wildlife and ecosystems, aquatic environment and surrounding rural areas. Will the establishment of proposed facility set a precedent for further industrial development and deter people from moving to the area? Land use implications of energy crop, especially since increasing land areas for this purpose could affect marginal and ecologically sensitive areas (wetlands, wildlife habitat) and conservation reserve program (CRP) lands.		
	Risk	Hazardous materials / Explosion	Fear of public health hazards, accidents.	Compliance with health and safety standards	
		Public Health and Safety	There may be long-term uncertainties about the general health impacts caused by the plant. Increases in local air pollution, chemical runoff and water pollution.	Compliance with environmental standards, permits	

Environmental characteristics of biomass gasification.

Biomass gasification is a relatively new technology; data on environmental impacts associated with the process are still being collected. Some, such as air emissions, are dependent on the type of gasifier and feedstock. As with direct combustion and co-firing, gasification can potentially reduce GHG emissions and produce a near net zero increase in atmospheric carbon dioxide. The U.S. DOE has estimated that carbon displacement from biomass gasification could displace at least 18 million tons of GHG from fossil fuels (Climate Vision 2009). SO_2 and NO_X emissions may also be decreased by 80-90% comparable with traditional energy production methods (Climate Vision 2009). Overall, facility air emissions are considerably reduced through the production and burning of syngas (see Table 21).

Upstream environmental characteristics associated with gasification of biomass are similar to those associated with direct combustion and co-firing described above.

Table 21. Potential environmental impacts of a biomass gasification facility.

<table>
<tr><th>Environmental Characteristic</th><th colspan="2">Impact</th><th colspan="2">Environmental Footprint</th><th>Level of Significance</th><th>Possible Mitigation of Impacts</th><th>Additional Notes</th></tr>
<tr><td rowspan="11">Air</td><td rowspan="11">Bubbling Fluidized Bed (BFB)</td><td rowspan="2">CO</td><td>Pulp Sludge</td><td>-</td><td rowspan="6">At temperatures higher than 1200-1300^{0}C, little or no methane, higher hydrocarbons or tar is formed and H_2 and CO production is maximized without requiring a further conversion step.</td><td rowspan="6">Installation of wet scrubbers can help reduce flue emissions including up to 50% of the tar in syngas and the potential to remove up to 97% of tars from end emissions</td><td rowspan="11">As a new technology, there is still limited data available on biomass gasification efficiency.</td></tr>
<tr><td>Wood</td><td>-</td></tr>
<tr><td rowspan="2">NO_x</td><td>Pulp Sludge</td><td>25ppm</td></tr>
<tr><td>Wood</td><td>-</td></tr>
<tr><td rowspan="2">SO_2</td><td>Pulp Sludge</td><td>9ppm</td></tr>
<tr><td>Wood</td><td>-</td></tr>
<tr><td rowspan="2">Organic Carbon</td><td>Pulp Sludge</td><td>-</td><td rowspan="5">Utilization of syngas reduces overall GHG emissions when compared to traditional power production.</td><td rowspan="5">Treatment of wastewater from scrubbers using settling chambers, sand and charcoal filtration, can produce effluent within EPA drinking water guidelines,</td></tr>
<tr><td>Wood</td><td>-</td></tr>
<tr><td rowspan="2">NH_3</td><td>Pulp Sludge</td><td>-</td></tr>
<tr><td>Wood</td><td>-</td></tr>
<tr><td>H_2S</td><td>Pulp Sludge</td><td>-</td></tr>
</table>

			Wood -			
	Centralized Fluidized Bed (CFB)	CO	Bark 250mg/m^3	Circulating fluidized bed gasification has not been tested to the same extent at BFB, emission figures may change with further development of the technology	Use of steam reforming catalysts for naphthas has been found more effective at removing tar from emissions compared to commercial steam reforming catalysts for light hydrocarbons	
		NO_x	Bark 250mg/m^3			
		SO_2	Bark 100mg/m^3			
		Organic Carbon	Bark 150mg/m^3			
		NH_3	Bark 5mg/m^3			
		H_2S	Bark 5mg/m^3			
	Fixed Bed (FB)	CO	MSW -	Tendency to produce larger quantities of tar compared to other gasifier types	Downdraft gasifiers can consume up to 99.9% of the tar formed, minimizing tar clean-up	
		NO_x	MSW 120ppm			
		SO_2	MSW 79ppm			
		Organic Carbon	MSW <10ppm			
		NH_3	MSW -			
		H_2S	MSW -			
	Black Liquor Gas Combined	CO	Black Liquor Solids 0.41 lbs/ton BLS	-	Bubbling fluid beds and	

	Cycle	NO_x	Black Liquor Solids	1 lbs/ton BLS		circulating fluidized bed gasifiers provide possible high converse rates with low tar and unconverted carbon	
		SO_2	Black Liquor Solids	0.04 lbs/ton BLS			
		Organic Carbon	Black Liquor Solids	-	-		
		NH_3	Black Liquor Solids	-			
		H_2S	Black Liquor Solids	-			
	Upstream Emission (g kWh–1)	CO	1.81		Despite production of upstream emissions through cultivation and transport, overall environmental footprint is still reduced comparable with coal only combustion	Radius of biomass collection limited to 50miles	
		NO_x	12.0 - 14.0				
		Particulates	0.4 - 0.59				
		Hydrocarbons	0.76				
Land	Agricultural land	Land Resource	-		Possibility that energy crop production will reduce food crop land	Use of conservation reserve program (CRP) land to grow dedicated energy crop	-
		Crop Type	Short Rotation Woody Crop	Willow carbon sequestration (SOC) 296g m^{-2} yr^{-1}	Carbon sequestration dependant on specific crop type, farming practice, climate, soil conditions and current soil carbon saturation. Ranges may vary from 36 - 710 g m^{-2} yr^{-1}	-	-
			Herbaceous Crop	Switchgrass carbon sequestration (SOC) 298g m^{-2} yr^{-1}			
			Forest Residue	Average carbon sequestration (SOC) 338g m^{-2} yr^{-1}			
		Herbicides and Pesticides	Short Rotation Wood Crop	12 times less herbicides and 19 times less insecticides compared to corn production	Energy crops act as filter systems, removing pesticides and excess fertilizers from surface water	-	-

			Herbaceous Crop (Switchgrass)	Equal amounts of herbicide compared to corn production. Insecticide is rarely used			
		Fertilizers	Increased use of fertilizer (Potassium and Nitrogen)		Nutrient overload in surrounding areas	Short rotation coppice, miscanthus and other favored energy crops require lower fertilizer inputs than common agricultural crops. Recycling of nutrients by using ash waste from co-firing reduces the need for chemical inputs.	
	Municipal Land	Existing Facilities	-		-	-	-
		Landfills	CO_2	73.8kg / 100Kg oven dried biomass	During landfill decomposition, wood waste releases roughly equal amounts of methane and carbon dioxide. Combustion mitigates this impact.	Removal of wood waste from landfills.	-
			CH_4	18.3Kg / 100Kg oven dried biomass			
	Solid Waste - Char/Ash (kg/kg feed)	BFB	Pulp Sludge	0.091	Ash deposition rates not affected significantly when co-firing wood or similar low-ash, low alkali, low-chlorine fuels.	Inclusion of ash removal system	Gasification of MSW and sewage sludge can result in ash containing heavy metals, which can leach into water and soils if ash is not properly disposed of
			Wood	0.03		Low temperature operation keeps temperatures below the flow temperature of the ash	

		CFB	Bark	0.01-0.04		High temperature operation keeps temperatures above the melting point of ash	
		FB	MSW	10			
Water	Usage	Facility	-		-	-	Increases in water consumption considered negligible compared to coal-only operation
		Biomass Cultivation	Short Rotation Woody Crop (poplar)	$42m^3/GJ$	Water usage from the cultivation and production of energy from biomass is 70-400 times larger than the amount of water used to create energy from a mix of non-renewable resources. This wide range is dependent on differences in crop characteristics, agriculture production conditions and climatic circumstance.	Average water usage for bioenergy crops grown in the US is $58m^3/GJ$. Cultivation of perennial low input crops reduces need for water (switchgrass)	-
			Herbaceous Crop (Miscanthus)	$37m^3/GJ$			
	Quality	-	-		Runoff during crop establishment could be comparable to or greater than that from annual row crops, especially for tree crops treated with herbicides to suppress competing vegetation		It has been projected that displacing annual crops with perennial biomass crops would reduce runoff -- decreasing soil erosion and improving water quality

	Liquid Waste	Sewage	-	-	-	-
		Industrial Waste	-	Use of wet scrubbers to mitigate emissions and tar results in the production of wastewater	Settling beds, sand and charcoal filtration can be used to clean waste water	-

Table 22. Possible public opposition to the establishment of a biomass gasification facility.

Environmental Characteristic	Impact	Sub Category	Level of Significance	Possible Mitigation of Impacts	Additional Notes
Community	Public nuisance	Odor	Will plant emissions create undesirable odors?	-	-
		Noise	Plant processing noise as well as additional traffic associated with the plant.	Compliance with local noise standards; scheduling of truck traffic at appropriate times	-
		Vibration	Minimal	-	-
		Increased traffic	Increases in traffic movement and flow of high goods vehicles. Damage to road systems through increased heavy traffic and possible additional expense to taxpayer.	-	-
	Resources	Demand on community services	Demands (and costs) increase with new or expanded facilities. If development leads to population increase, this can put added pressure on infrastructure	-	-
		Use of existing facilities	Can existing facilities be retrofitted thus mitigating impact to community and environment?	Prior land use replaced by plantation. On degraded lands or excess agricultural lands. Plantations should never replace natural forests.	-
	Quality of local area	Economy	Could affect property prices, tourism and business	-	-
		Aesthetics	Visual impact may be significant to the community, as may potential plant or animal habitat loss.	-	-
		Future open spaces / recreational land	Fear of negative impacts to wildlife and ecosystems, aquatic environment and surrounding rural areas. Will the establishment of proposed facility set a precedent for further industrial development and deter people from moving to the area? Land use implications of energy crops, especially since increasing land areas for this purpose could affect marginal and ecologically sensitive areas (wetlands, wildlife habitat) and conservation reserve program (CRP) lands.	-	-
	Risk	Hazardous materials / Explosion	Fear of public health hazards, accidents.	Compliance with health and safety standards	-

		Public Health and Safety	Uncertainties about general health impacts (air pollution, chemical runoff and water pollution).	Compliance with health and safety standards, environmental regulations and permits	-

Environmental Review And Permitting

Before a biomass energy plant can be constructed, numerous discretionary approvals must be obtained from local municipal boards, state agencies and, in some cases, from federal agencies. In New York, most projects will be required to undergo an environmental review under the State Environmental Quality Review Act (SEQRA). New York City has a separate but similar City Environmental Quality Review (CEQR). In addition, if the federal government funds a project partially or in its entirety, the project will also be subjected to the National Environmental Policy Act (NEPA).

State Environmental Quality Review Act (SEQRA)

This section provides an overview of the SEQRA process. It is meant to help developers understand the objectives and methods of the SEQRA program. For more detailed and complete information on SEQRA, refer to SEQRA guidance documents available online at the NYSDEC's website, at http://www.dec.ny.gov/regulations/2374.html.

Under the State Environmental Quality Review Act (SEQRA), an environmental review of the project must be conducted before permits are issued. The SEQRA process begins with the lead agency (the agency taking responsibility for the SEQRA process) classifying the project as either a "Type I," a "Type II" or an "Unlisted" action. If the project is considered a "Type II" action, the SEQRA process ends and further environmental review is not required. Otherwise, further review under SEQRA is required.

For projects classified as Type I or Unlisted, the lead agency, with input from other interested agencies, must determine whether the action will have a significant environmental impact, considering the following areas of potential impact:

6 NYCRR Part 617.7(c) Criteria for determining significance:

(1) These criteria are considered indicators of significant adverse impacts on the environment:
(i) A substantial adverse change in existing air quality, ground or surface water quality or quantity, traffic or noise levels; a substantial increase in solid waste production; a substantial increase in potential for erosion, flooding, leaching or drainage problems;
(ii) The removal or destruction of large quantities of vegetation or fauna; substantial interference with the movement of any resident or migratory fish or wildlife species; impacts on a significant habitat area; substantial adverse impacts on a threatened or endangered species of animal or plant, or the habitat of such a species; or other significant adverse impacts to natural resources;
(iii) The impairment of the environmental characteristics of a Critical Environmental Area as designated pursuant to subdivision 617.14(g) of this Part;
(iv) The creation of a material conflict with a community's current plans or goals as officially approved or adopted;
(v) The impairment of the character or quality of important historical, archeological, architectural, or aesthetic resources or of existing community or neighborhood character;
(vi) A major change in the use of either the quantity or type of energy;
(vii) The creation of a hazard to human health;
(viii) A substantial change in the use, or intensity of use, of land including agricultural, open space or recreational resources, or in its capacity to support existing uses;
(ix) The encouraging or attracting of a large number of people to a place or places for more than a few days, compared to the number of people who would come to such place absent the action;
(x) The creation of a material demand for other actions that would result in one of the above consequences;
(xi) Changes in two or more elements of the environment, no one of which has a significant impact on the environment, but when considered together result in a substantial adverse impact on the environment; or
(xii) Two or more related actions undertaken, funded or approved by an agency, none of which has or would have a significant impact on the environment, but when considered cumulatively would meet one or more of the criteria in this subdivision.

If the lead agency makes a negative determination, the SEQR process ends. If it makes a positive determination, it must create a draft Environmental Impact Statement (EIS), which will contain information on potentially significant environmental impacts of the project, mitigation measures that could minimize these impacts, and a range of reasonable alternatives to the proposed project. It must then make the draft EIS available for public comment. Once public comment is received, the agency must create a final EIS in response to the comments, identifying its proposed final action. Finally, each involved agency must certify that all requirements of SEQRA have been met and that the chosen action avoids or minimizes adverse environmental impacts. Once this certification has been obtained, the lead agency may undergo its final action.[41]

National Environmental Policy Act (NEPA)

NEPA requires federal agencies to take into consideration the environmental impacts and alternatives of any proposed action that is federally funded or undertaken directly by a federal agency. Depending on the effect the proposed project will have on the environment, there are three different levels of review. First, the proponent agencies have listed certain actions as "categorical exclusions", which implies that these actions are exempt from review. Thus, when a project involves federal funding, the first step is to determine if the action has been categorically excluded from NEPA application. Second, if the action has not been categorically excluded, the agency involved in the project must prepare an environmental assessment (EA), which will be subject to notice and public comments. If the EA determines that the action will not have a significant effect on the environment, the agency issues a "finding of no significant impact" (FONSI) and the NEPA review process is over. However, if the EA concludes the proposed action will have a significant effect on the environment, the agency must prepare an "environmental impact statement" (EIS). NEPA documents must be filed with the federal Environmental Protection Agency (EPA) for review.[42]

Air Pollution Control

Advice on addressing air pollution permit responsibilities is presented in Guidebook Chapter 1 – Crosscutting Issues: Environmental Regulations And Permitting. This appendix outlines air permit responsibilities generally.

Biomass energy projects, such as gasification facilities and direct and co-firing systems, will most likely generate air pollutants (i.e. particulate matter (PM), sulfur dioxide (SO_2) nitrous oxide (NO_2), ozone, etc.) as a result of the electricity generation process. In order to release these pollutants into the ambient air these biomass energy facilities will be required to obtain an air quality permit from federal, state and/or local authorities.

At the federal level, air pollution is regulated under the Clean Air Act (CAA). The CAA authorizes the EPA to limit the amount of pollutants that mobile and stationary sources can emit into the ambient air. The EPA enforces such emissions limitations through a permitting program, which in some cases is directly administered by the individual states through a "state implementation plan".[43] New York administers its own air pollution program.

Under the Clean Air Act and New York State law and regulations, the Department of Environmental Conservation's Division of Air Resources (DAR) administers the State's air pollution permitting program. The two most common types of air pollution control permits issued by the DAR are Title V facility permits, and state facility permits. Title V facilities include facilities that are considered "major" or that are subject to New Source Performance Standards (NSPS) (*see* 6 NYCRR Part 201-6). A facility is considered "major" if it emits or has the potential to emit at least 100 tons per year of a regulated pollutant, which includes NO_x, SO_x, and particulates. Facilities subject to state facility permits generally fall under one of the following categories: their actual emissions exceed 50% of the threshold that would make them major

41 http://www.dec.ny.gov/permits/6189.html
42 http://www.epa.gov/compliance/basics/nepa.html#oversight
43 http://www.epa.gov/air/caa/peg/understand.html

but their potential to emit does not meet this threshold; they require permit conditions that limit their emissions below levels that would otherwise make them subject to certain requirements; they have been granted variances from air regulations; or they are new facilities that are subject to NSPS or that emit hazardous pollutants (*see* 6 NYCRR Part 201-5).[44]

Some projects do not require air control permits. These include activities that are exempt or trivial (*see* 6 NYCRR Part 201-3) and facilities that are considered minor for air pollution purposes and therefore do not require permits but are required to be registered with the DEC (*see* NYCRR Part 201-4).

In addition to New York State's emissions limitations and permit requirements, any biomass facilities sited within New York county or within the City of New York (NYC) must comply with particular ambient air conditions for said areas. Biomass projects proposed for areas within NYC or the NYC watersheds should consult the NYC Department of Environmental Protection (DEP) for additional air pollution regulations.

Water Regulations

The construction and operation of a biomass facility may require several permits for the discharge of process wastewater and stormwater. In addition, the facility may require additional permits if the construction and/or operation of the same will likely disturb a wetland area. In New York, in most cases these permits are issued by the NYSDEC. Nevertheless, federal agencies such as the USEPA or the Army Corps of Engineers may be involved.

Relevant elements of New York State's water resource protection framework are outlined below.

Federal water pollution control

Water pollution is primarily regulated at the federal level by the Clean Water Act (CWA). The federal CWA prohibits any discharge of pollutants into national surface waters from a "point source"[45] without a permit. To enforce its provisions, the CWA established the National Pollutant Elimination Discharge System (NPDES) permit program. The NPDES program requires each discharger to obtain a permit to discharge pollutants into surface waters and to periodically submit discharge monitoring reports to the EPA. Moreover, the CWA prohibits the discharge of dredge and/or fill material into wetlands without a permit, known as the Section 404 permit. Section 404 permits are issued by the Army Corps of Engineers.

As the CAA, the CWA authorizes the EPA to allow individual states to administer their own NPDES program. When administered by a state, the NPDES program is referred to as the State Pollution Discharge Elimination System (SPDES). New York administers its SPDES permit program through the DEC. The New York SPDES is broader than the federal NPDES program as it covers point source discharges into groundwater as well as surface water.[46]

Wastewater regulations in New York

Biomass energy systems that eliminate wastewater discharge through a point source (i.e. discrete outlet or pipe) into a surface water body, groundwater, or into a sewage treatment plant are required to obtain a SPDES permit from the DEC unless the point source discharges less than 1,000 gallons per day of sewage wastewater (including animal manure) to groundwater and this wastewater does not contain industrial or

[44] http://www.dec.ny.gov/chemical/8569.html

[45] Section 502(14) of the CWA defines a "point source" as "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stock, concentrated animal feeding operation, or vessel or other floating craft, from which pollutants are or may be discharged. This term does not include agricultural stormwater discharges and return flows from irrigated agriculture."

[46] http://www.dec.ny.gov/permits/6054.html

any non-sewage waste.[47] Concentrated Animal Feeding Operations (CAFOs) may obtain a SPDES General Permit GP-0-09-001.[48] A dairy farm is considered a CAFO when it contains at least 200 mature dairy cows (milked or dry).[49]

Stormwater regulations in New York State

Developers of a proposed biomass project may also need to obtain a SPDES permit from the DEC for stormwater discharges. Stormwater is water from rain and melting snow that flows over buildings, paved surfaces, and soils, picking up pollutants along the way before being discharged into waterways.[50] If construction activities disturb one or more acres of land, the project will require a SPDES permit for Stormwater Discharges for Construction Activities, excluding certain agricultural projects.[51] Post-construction, project operators must ensure that their individual SPDES permit addresses stormwater discharges, obtain the SPDES Multi-Sector General Permit for Stormwater Discharges Associated with Industrial Activity, or certify under the No Exposure Exclusion that activities at the project site will not be exposed to stormwater.[52]

Freshwater Wetlands Regulations

If the project is located in a freshwater wetland or in one of its adjacent areas, it will require a permit if it may adversely impact the natural values of the wetland or its adjacent areas. The permitting authority is the Adirondack Park Agency (APA) if the project is located in the Adirondack Park. Otherwise the permitting authority is the DEC. However, normal agricultural activities, the harvesting of natural products, and selective cutting of trees and harvesting of firewood are exempt from freshwater wetlands permitting.[53]

Tidal Wetlands Regulations

If the project is located in a tidal wetland or in its adjacent areas and it will alter the wetland or its adjacent areas, it will require permitting by the DEC[54]. In addition, if the project requires dredging, discharging dredge or fill material, or constructing certain structures in wetlands and waterways, it will require a permit from the Army Corps of Engineers.[55]

Wild, Scenic and Recreational Rivers Regulations

Generally, no structures can be built within half a mile of a river designated by the DEC as possessing outstanding scenic, ecological, recreational, historical and scientific values.[56] These rivers are categorized as “Wild”, “Scenic”, and “Recreational”. Generally, no structures may be constructed within half a mile of these rivers without a permit from the DEC (unless the project is located in the Adirondack Park, in which case, an APA permit is required).[57] The DEC will not permit development within half a mile of a “Wild” river. For the other rivers, agricultural activities located at least 100 feet from the river bank do not require a permit. Forest management activities, which include the harvesting of woodland as part of a forest

[47] http://www.dec.ny.gov/permits/6306.html
[48] http://www.dec.ny.gov/docs/water_pdf/factsheetgp009001.pdf
[49] http://www.dec.ny.gov/docs/water_pdf/gp009001.pdf
[50] http://www.dec.ny.gov/chemical/8468.html
[51] http://www.dec.ny.gov/chemical/43133.html
[52] http://www.dec.ny.gov/chemical/9009.html
[53] http://www.dec.ny.gov/permits/6279.html
[54] http://www.dec.ny.gov/permits/6359.html
[55] http://www.dec.ny.gov/permits/6349.html
[56] http://www.dec.ny.gov/permits/6033.html
[57] http://www.dec.ny.gov/regs/4610.html

management program, do not require a permit if they are located on slopes of 15% or less, beyond the 100-year floodplain, and/or are located at least 150 feet from the banks of a “Recreational” river and at least 250 feet from the banks of a “Scenic” river.

Adirondack Park Agency Regulations

If the project is located within the Adirondack Park, it may be subject to Adirondack Park Agency (APA) regulations.[58] APA approval is needed for projects being developed in designated critical environmental areas, within a quarter mile of a designated wild, scenic and recreational river, as well as in other designated areas within the Park. Please visit http://www.apa.state.ny.us/Property_Owners/permitChecklist.html to determine whether your Adirondack Park-located project requires APA approval.

Solid Waste Regulations

Biomass energy facilities use diverse materials as feedstock, ranging from forest and agricultural resources to animal waste to construction materials. In some cases, these materials are grown on-site to be used as a fuel source of the biomass facility. However, some materials used as biomass feedstock come from discarded materials that have entered the solid waste disposal chain. In the latter case, the biomass facility and/or the feedstock is most likely regulated under federal, state and local waste management laws and regulations.

Resource Conservation and Recovery Act (RCRA)

At the federal level, the EPA administers the Resource Conservation and Recovery Act (RCRA), which establishes a regulatory framework for the management of solid waste. Under RCRA, solid waste is either classified as nonhazardous or as hazardous waste. The solid waste classifications are regulated separately. In particular, RCRA Subtitle D establishes general guidelines for the handling and disposal of nonhazardous solid waste. The management of nonhazardous solid waste is mostly delegated to the states and local governments. The EPA retains authority over some aspects of the design and operation of solid waste disposal facilities.[59] New York State administers its own RCRA program.

On the other hand, RCRA Subtitle C creates a very rigorous federal program for the management of hazardous waste. Under RCRA, solid waste that is listed as hazardous waste or that exhibits hazardous characteristics must be handled in accordance with strict guidelines. In essence, in a “cradle-to-grave” approach, RCRA’s Subtitle C regulations cover the generation, transportation, and treatment, storage and disposal of hazardous waste.

New York State’s Solid Waste Management Program

Biomass projects may require a Solid Waste Management Program permit from the DEC under 6 NYCRR Part 360 as a solid waste management facility. Under Part 360, solid waste is defined as “any garbage, refuse, sludge from a wastewater treatment plant, water supply treatment plant, air pollution control facility and other discarded materials including solid, liquid, semi-solid or contained gaseous materials, resulting from industrial, commercial, mining and agricultural operations.”[60] Additionally, discarded material is defined as that “disposed, burned/incinerated, including burned as fuel for the purpose of recovering usable heat, or accumulated, stored or physically, chemically or biologically treated instead of or before being

[58] http://www.dec.ny.gov/permits/6238.html
[59] http://epa.gov/epawaste/inforesources/pubs/orientat/index.htm
[60] http://www.dec.ny.gov/regs/4415.html

disposed of."[61] There are Part 360 exemptions for certain solid wastes that are beneficially used under the Beneficial Use Determination Regulations (*see* 6 NYCRR Part 360-1.15(b)).[62] Biomass projects are not specifically addressed by DEC solid waste regulations. Therefore, the determination of whether a Solid Waste Management Program permit is required for a biomass facility depends on the type of feedstock used, the size of the facility, and its location. Project developers should meet early in the development process with the state, regional and local authorities to address how the biomass facility will be classified in the state, regional or local solid waste management plan.

Waste Transporter Regulations

Those transporting regulated waste generated or disposed in New York require a Part 364 waste transporter permit from the DEC. Regulated waste includes nonhazardous byproducts of an industrial or commercial process, waste oil, and nonresidential raw sewage or sewage-contaminated waste. Transporters of municipal solid waste and of a single truckload of non-hazardous regulated waste (except medical waste and residential septage) weighing less than 500 pounds are exempt from this permit.[63]

Coastal Zone Management Regulations

Biomass energy facilities sited near coastal areas and inland waterways need to consider federal, state and local coastal zone management regulations prior to beginning construction and operation. Through the Waterfront Revitalization of Coastal Areas and Inland Waterways Act (Waterfront Revitalization Act), New York State regulates the use and protection of the State's coasts and waterways.[64] The New York State Department of State is the agency in charge of administering the state's coastal zone management program. Following the direction provided by the Waterfront Revitalization Act, local authorities have enacted their own Local Water Revitalization Programs to further regulate the use of coastal zones in their communities. Therefore, developers of biomass energy projects that could possibly affect coastal areas or inland waterways should consult with both the state and the local government to determine the specific state and local requirements for the proposed site of the facility.

In addition, biomass projects that are funded in part or in their entirety by federal and/or state entities must comply with additional requirements set by the New York State Department of State or the federal agency involved. At the federal level, the Coastal Zone Management Act, administered by the Department of Commerce's National Oceanic and Atmospheric Administration (NOAA), requires all federal agencies taking a direct action or funding an action to carry out the same in a manner consistent with the state and/or local coastal zone management policies.[65] To that effect,, if a biomass project is in a coastal area and requires federal approval, the lead agency must obtain a Coastal Consistency Certification from the New York State Department of State.[66] Conversely, if the project is in a coastal area and requires state, instead of federal approval, the applicable state agency must complete a Coastal Assessment Form in order to ensure that the state action is consistent with state coastal policies.[67]

[61] http://www.dec.ny.gov/regs/4415.html
[62] http://www.dec.ny.gov/chemical/8498.html
[63] http://www.dec.ny.gov/chemical/8785.html
[64] http://www.nyswaterfronts.com/consistency_coastalpolicies.asp
[65] http://www.nyswaterfronts.com/consistency.asp
[66] http://www.nyswaterfronts.com/consistency_federal.asp
[67] http://www.nyswaterfronts.com/consistency_state.asp

New York State Office Of General Services (OGS) Regulations

If your project involves New York State-owned underwater lands, you may need to obtain approvals or easements of their use from the OGS before commencing the project.[68] Visit http://www.ogs.state.ny.us/aboutOGS/regulations/statutes/chapter2.html for more information.

Local Regulations

Land use regulation in New York State is largely within the jurisdiction of local municipalities (towns, cities, villages and hamlets), meaning that each project must be individually planned to comply with the requirements set by the municipality or municipalities within which it lies. The developer of a biomass project will likely have to address the local planning board and/or town board, the zoning board of appeals (ZBA), the building department, and other regulatory and advisory entities created by the local legislature.

In general, planning boards have the authority to evaluate applications for rezoning, subdivision, site plan review, variances and the issuance of special use permits. In addition, planning boards (or, in some cases, town boards) oversee a project's compliance with SEQRA and serve as an advisor to the local ZBA or other local entities.[69] ZBAs serve as local appellate fora, with authority to interpret local zoning regulations and to hear claims for wrongly issued or denied permits and for misapplication of zoning maps and/or regulations. In addition, in certain municipalities the ZBA may have appellate jurisdiction to grant variances and special use permits. Finally, the local department of building is the local body authorized to issue certificates of occupation for a facility and oversee building regulations.[70] Although building requirements are not necessarily environmental in nature, they are an integral part of local permitting and must be considered holistically with the related environmental requirements.

[68] http://www.dec.ny.gov/permits/6269.html
[69] NYS Local Government Handbook, available at http://www.nysl.nysed.gov/scandocs/.
[70] NYS Local Government Handbook, available at http://www.nysl.nysed.gov/scandocs/.

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APPENDIX C: RESOURCE ASSESSMENT

Biomass Market Information

The number of biomass facility and component vendors is increasing as biomass technologies penetrate the U.S. market. There are many sources of information on such vendors, including chambers of commerce and business registries. One source of information on vendors, sorted by state, can be found at: http://energy.sourceguides.com/businesses/byGeo/US/byP/biomass/boiler/boilers.shtml

Biomass feedstock and fuel suppliers are similarly increasing in number. Some online resources for locating biomass suppliers are listed below:

http://www.dec.ny.gov/docs/lands_forests_pdf/primary.pdf (Directory of Primary Wood-Using Industry in New York State)
http://www.dec.ny.gov/docs/lands_forests_pdf/secondary.pdf (Directory of secondary wood products manufacturers in New York State.
http://www.dec.ny.gov/docs/lands_forests_pdf/spr2008winter.pdf (Price report on stumpage and cordwood price in New York State, winter 2009).
http://www.dec.ny.gov/lands/46935.html (Low-Grade/Underutilized Timber and Mill Residue Products Markets).
http://www.biomassconnections.com/forum (Biomass connections online forum)
http://www.recycle.net/exchange/index.html (Online listing of available and wanted materials)

On future source of information is the NYS Biomass Energy Alliance (formed April 1, 2009). This organization has no online resources as yet, but may be accessed by email: info@newyorkbiomass.org, or telephone: (315) 453 3823.

Resource Assessment Summary Report

The following summarizes the availability of resources and potential for development, by region, for each of the three biomass technologies addressed in this guidebook.

Agriculture Digester Technology

Agricultural digesters use organic materials, mostly manure and food waste, as their feedstock. The manure used for most agricultural digester facilities, both nationally and in New York, is collected from dairy operations.[71] According to the AgStar Program, as of February 2009, there were 13 manure agricultural digesters operating in New York with a combined capacity of 15,904 MWh.[72] Twelve of the operational digesters in New York use manure collected from dairy farms, while the remaining one uses manure from a duck farm. The operational digesters in New York are spread out over nine counties, with the major concentration located in the Finger Lakes region.

Because of the high cost of transporting manure, agricultural digesters are most likely to be successfully developed in areas with large concentration of dairy farms. At present, dairy production in New York is concentrated in Central and Western New York with some significant activity in the Thousand Islands Seaway region, north of the Adirondacks. Counties located in the Lower Hudson Valley, New York City and Long Island lack dairy operations and are therefore unlikely sites for agricultural digesters.

New York has great potential to expand the use of agricultural digesters for energy production. Currently, there are more than 5,600 dairy farms in New York State with a combined amount of more than 620,000

[71] http://www.epa.gov/agstar//operational.html
[72] http://www.epa.gov/agstar//news/digest/

milk cows.[73] Moreover, New York has an inventory of over 100,000 beef cows, 85,000 hogs and pigs, and 2.4 million chickens (4,000,000 layers and 2,000,000 broilers). In addition, according to Cornell University's Manure Management Program, New York State has nine identified food waste sources: food processing facilities/plants; supermarkets; fast food franchises; correctional facilities; restaurants; colleges/universities; K-12 public schools; hospitals; and nursing homes.[74] These facilities are the best source of food waste for use in agricultural digesters. Food processing facilities are concentrated in the Niagara Frontier region in Western New York and in Long Island.

Biomass gasification

The primary feedstocks used in biomass gasification are low-grade woody biomass, urban wood wastes and/or residue from industrial mills. Usually, the low-grade timber used for gasification processes is obtained from the residues of harvesting, thinning and land-clearing activities conducted on commercial logging and silvicultural operations and from municipal solid waste. The feasibility of biomass gasification projects greatly depends on the availability and proximity of these feedstocks, which are generally drawn from an area within a 30- to 50-mile radius around the gasifier.

Approximately 62% of NYS is forested, with the major forested areas concentrated in the Adirondack and the Catskills Forest Preserves; other significant forested areas exist in Central and Western New York. The forestry industry, which includes commercial logging, is well established in NYS and it contributes $4.6 billion annually to the State's economy.[75]

Markets for primary and secondary wood products in New York State are well-established. However, low-grade timber resources are underused throughout most of the State. According to the New York State Department of Environmental Conservation, there exist several low-grade/underutilized timber and mill residue products markets in New York, which are concentrated in the Adirondacks, the Finger Lakes and the Niagara Frontier regions.[76] The market for low-grade timber offers a variety of grades of wood appropriate for biomass facilities. These include pulpwood (clean wood chips), bole chips (wood with bark), and whole tree chips, also called hog fuel or "dirty" chips (whole trees fed into a grinder).

Municipal waste streams are more difficult to quantify, however, there are established recycling operations that could supply feedstocks to gasification projects. MSW streams are most robust in the urban, densely populated areas of the state, including New York City and its surrounding suburbs; Long Island; and the several upstate metropolitan regions (i.e., Albany-Schenectady-Troy, Binghamton, Buffalo, Rochester, and Syracuse).

Based on this analysis of feedstock availability, gasification projects are most likely be developed in upstate New York, within geographical proximity of low-grade wood supplies in the Adirondacks, Catskills, Finger Lakes and Niagara Frontier regions; or in the more densely populated areas of the state, where municipal waste streams offer inexpensive fuel. However, it is worth noting that development of such projects, which are likely to be viewed as experimental and risky due to the lack of commercial precedents, may be more difficult in densely populated areas.

Biomass direct-firing and co-firing

In New York, wood is and will most likely continue to be the most common feedstock for biomass direct combustion and co-firing operations. Sources include waste wood (i.e. urban waste wood, mill and industrial residues) and forestry products. Dedicated woody energy crops may eventually become a viable fuel source, but at present are too expensive and not widely available. Crop residues are not generally

[73]http://www.agcensus.usda.gov/Publications/2007/Full_Report/Volume_1,_Chapter_1_State_Level/New_York/index.asp
[74] http://wastetoenergy.bee.cornell.edu/IMS/default.asp
[75] http://www.dec.ny.gov/lands/309.html
[76] http://www.dec.ny.gov/lands/46935.html

available in sufficient quantities, and grasses are difficult to process and handle, present combustion system maintenance problems, and lack developed supply chains.

Due to feedstock transportation costs, wood-fed biomass combustion operations will likely be confined to the same forested regions as biomass gasification facilities, e.g. the waste wood and forestry markets located in the Adirondacks, the Niagara Frontier and the Finger Lakes regions. Existing and emerging wood markets in those regions can serve as an incentive for development of biomass combustion facilities. Wood brokers will be an essential component in the emerging market for waste wood and low-grade forest products.

Facilities designed to use urban waste wood as their primary feedstock can be located near urban centers. However, some of these feedstocks carry the risk of contamination, and electricity generated through the direct combustion of such feedstocks may not qualify under the RPS. In addition, environmental permitting requirements may be more difficult to satisfy for facilities burning wood from recycling centers and other municipal waste streams.

Note that NYSERDA's soon-to-be-released Renewable Fuels Roadmap will include an assessment of biofuels availability and market dynamics in New York.

APPENDIX D: EVALUATING ECONOMIC VIABILITY

This appendix provides guidance on the financial and economic assessment of biomass projects using the technologies considered in the guidebook. More information on this topic is presented in Chapter 2 – Crosscutting Issues: Financing.

There are several ways to evaluate the economic viability of a potential project. The two most common are simple payback analysis and discounted cash flow analysis (DCF). Both methods require determining costs, revenues, and savings attributable to the project, determining the comparable costs of a baseline or alternative case, and developing net annual cash flows (pro forma). Key distinctions are that DCF always takes into account the time value of money and examines the total life of the project, using such metrics as the net present value (NPV) of future earnings, life cycle cost (LCC), and internal rate of return (IRR). Simple payback, by comparison, gives equal weight to all cash flows before the payback date and no weight to any subsequent cash flows.

Simple Payback Analysis

Companies frequently require that the initial outlay for any project be recoverable within some specified period of time. This is defined as the payback period. It is calculated by determining the number of years it takes before the cumulative cash flows equal the initial investment. Some consider just a "simple payback" where no discount rate is applied.

In simple terms, simple payback can be defined as:

Simple Payback Period (years) = Investment Costs ($)/Annual Savings ($/yr)

Companies using a simple payback period typically define a cutoff period (e.g., two years) and will not accept projects whose payback takes longer than the cutoff. One of the pitfalls of using a payback rule is that a company will tend to accept too many short-lived projects and too few longer-lived ones, despite the fact that they may have positive net present values.

Discounted Cash Flow/Net Present Value Analysis

DCF analysis examines the total costs and revenues during the life of a project and determines the sum of the present values of all cash flows. This is sometimes referred to as a net present value (NPV) or discounted cash flow (DCF) analysis. It depends solely on the forecasted cash flows from the project and the opportunity cost of capital and recognizes the time value of money by applying a discount rate to future cash flows. The discount rate is the opportunity cost of capital, in other words, the expected rate of return offered by other assets equivalent in risk to the project(s) being considered. In simple terms LCC can be defined as follows, where PV means present value:

Net Present Value = PV(Investment costs) + PV(Non-fuel operations and maintenance costs) + PV(Energy costs) + PV(Other costs) + PV(Other revenues)

In the case of a biomass CHP or thermal project the present value of energy costs are energy savings relative to the baseline alternative.

Only projects with a forecasted positive net present value should be pursued. When comparing multiple mutually exclusive alternatives the project with the higher net present value is the preferred choice.

Closely related to net present value is "internal rate of return" (IRR). The IRR is the discount rate at which the net present value of a project is zero. Some companies use investment rules dependent on IRR. In those cases, only projects with IRR greater than the internal cost of capital are accepted. Whenever the net present value of a project is a smooth declining function of the discount rate, this IRR rule is equivalent to accepting project investments with positive net present value.

Data Needs of Economic Evaluation

Much of the data and assumptions required to make a reasonable evaluation is gathered in the process of site assessment described in the Guidebook; past utility bills, quotes from equipment providers and packagers, or public sources of key equipment costs and performance. Typical but not all possible data needs are broken down below.

- Determine Biomass Supply Costs
  - Local sources of biomass (dry tons/day)
  - Moisture contents of biomass (%)
  - Fuel composition
  - Tipping fee costs or revenues if applicable ($/ton)
  - Feedstock sorting costs if applicable ($/ton)
  - Treatment and drying equipment costs ($/ton)
  - Current and projected ($/ton)
  - Delivery costs ($/ton)
  - Other revenues – tipping fees ($/ton)

- Determine Electricity and Demand Displaced by Biomass System
  - Electric capacity (kW)
  - Site annual peak demand (kW)
  - Site annual electricity usage including daily and seasonal variations (kWh)
  - Power island equipment availability (%)
  - Site electric load displaced by project (kWh/year)
  - Electricity sold to utility/wholesale market (kWh/year)
  - Monthly peak demand (kW)
  - Average monthly demand reduction (kW)

- Determine Fuel Thermal Load Served by the Biomass System
  - Thermal energy (MMBtu/year)
  - Existing site boiler/furnace efficiency (%)
  - Efficiency of biomass-fueled equipment (%)
  - Baseline site fuel displaced by biomass system if any (MMBtu/year)

- Determine Fuel Consumption of Biomass System
  - Site electric load displaced by biomass system (kWh/year)
  - Electricity sold back to utility (kWh/year)
  - Electrical efficiency (% HHV) or heat rate (Btu/kWh)
  - Fuel consumption (MMBtu/year and tons/day)

- Determine Energy Savings
  - Electricity displaced (summer/winter, on/mid/off peak kWh)
  - Displaced demand (summer/winter kW)
  - Electricity sell back (kWh)
  - Ratchet demand or stand-by charge ($/kW)
  - Electricity rates ($/kW and $/kWh)
  - Buy back electricity rate ($/kWh)
  - Displaced fuel rate if any ($/MMBtu)
  - Biomass fuel consumption rate ($/MMBtu or tons/day)
  - Value of displaced electricity
  - Electricity sell back ($/year)
  - Total cost of fuel ($/ton)
  - Forecast future year energy costs (escalation factors are sector and site specific)
  - Supply curves for all alternative sources of fuel ($/ton)

- Determine Total Investment Costs
    - Required site modifications ($)
    - Fuel handling and treatment equipment costs ($)
    - Feedstock storage costs ($)
    - Energy conversion capital equipment is applicable – e.g. gasifier or digester ($)
    - Converted fuel gas conditioning equipment ($)
    - Genset equipment costs ($/kW)
    - Boiler modifications if applicable ($)
    - Emissions control equipment if applicable ($)
    - Heat recovery equipment cost ($)
    - Heat recovery utilization equipment cost ($)
    - Controls and interconnect costs if required ($)
    - Ash handling equipment if applicable ($)
    - Electrical switchgear ($)
    - Electrical transformers ($)
    - Labor and materials ($)
    - Project and construction management ($)
    - Engineering and permitting fees/schedule ($)
    - Contingency (% of investment costs)

- Determine Financing Options
    - Debt to equity ratio
    - Interest rate
    - Internal cost of capital
    - Depreciation schedule
    - Leasing terms if applicable
    - Construction schedule

Inclusion of the value of incentives related to renewable and clean energy also needs to be a part of any biomass project economic assessment. These include but are not limited to those listed in Table 25.

Table 23. Biomass Project Incentives.

Investment Tax Credit	An investment tax credit (ITC) allows a taxpayer to take a fixed percentage from the cost of an eligible energy project as a credit against taxes. In short, an ITC effectively reduces income taxes for qualified tax-paying owners based on capital investment in eligible energy projects. ITCs for various investments are authorized by both the federal and state governments. At the federal level, developers of biomass energy projects can elect to take an ITC of 10% of the cost of the project during the taxable year in which the energy project was put in service (initiated operation). (Internal Revenue Code, §48). The American Recovery and Reinvestment Act of 2009 (ARRA) extended the ITC for biomass projects until January 1, 2014. Therefore, to take advantage of the ITC, biomass energy projects must be put into service by the deadline of the ITC. It is worth noting that to qualify for the federal investment tax credit, the property for which the ITC is sought must have been constructed or reconstructed by the taxpayer. Nonetheless, if the taxpayer acquired the property at a later time, the use of the property, in this case energy production, must have been initiated by the taxpayer. (IRS Form 3468, Investment Credit). Prior to the enactment of the ARRA in February 2009, the energy tax credits could be undercut by a "double dipping" provision that reduced or barred the use of the credits if the energy project was in some way financed by federal, state or local subsidies. However, the ARRA repealed this limitation and now energy projects, individual or commercial, are eligible for the full amount of the renewable energy tax credits. Note that biomass energy properties that qualify for grants under the ARRA are not eligible for any energy credits, including ITC. Although the ITC and other tax credits are key for the future development of large scale renewable energy facilities, these types of incentives are likely not adequate for small-scale projects, such as biomass facilities with a capacity under 10 MW. The reason for this discrepancy is that small-scale projects might not have sufficient tax liability to take advantage of them. Federal support for wind power comes in the form of the federal production tax credit (PTC) and accelerated depreciation. However, these incentives benefit only those project owners with tax liability sufficient to take advantage of them. Small-scale projects that do not have sufficient tax liability to take advantage of tax incentives can opt to apply for cash grants, discussed below.
Production Tax Credit	A production tax credit (PTC) allows a taxpayer to take a credit on a per kilowatt-hour basis for renewable energy generated at a qualified energy facility. At the federal level, biomass facilities qualify for a PTC. However, the amount of the PTC depends on the type of biomass technology in use. In particular, closed-loop biomass projects (i.e. dedicated energy crops) can elect for a 2.1¢ / kWh PTC while open-loop biomass projects (i.e. waste biomass) can opt for a 1¢/kWh PTC. Under the ARRA, closed-loop and open-loop biomass projects put into service before January 1, 2013 are eligible for the PTC. The PTC for closed-loop projects lasts for 10 years after the election. PTC for open-loop projects lasts only 5 years. (DSIRE, Renewable Electricity Production Tax Credit). In New York, biomass facilities using anaerobic digesters to generate energy may qualify for a PTC. (DSIRE, New York Incentives).

	As discussed above in the ITC section, the ARRA eliminated the "double dipping" provisions of previous laws that limited the eligibility of projects for tax incentives if the projects were subsidized by the federal, state or local governments. At present, all qualified energy projects, such as biomass energy facilities, can take advantage of the ITC or the PTC. Note that biomass energy properties that qualify for grants under the ARRA are not eligible for any energy credits. Also, note that small-scale energy projects with a small tax liability may not take full advantage of the PTC and will be more benefited by using other types of incentives, such as cash grants.
Cash Grants	A cash grant is a monetary amount provided to an energy developer by a public or private entity to cover a percentage of the costs of the energy project. The 2009 ARRA created a new renewable energy grant program. Under the ARRA grant program, biomass projects put into service in 2009 or 2010 will have the option of taking a cash grant from the Department of Treasury in lieu of the ITC or PTC energy credits. Biomass projects are eligible for a 30% grant. As of this writing, the Department of Treasury will accept grant applications until October 1, 2011. Note that only tax-paying entities are eligible for the grant. States, municipalities, non-profits, members of pass-through entities cannot opt for the cash grant incentive. (DSIRE, Renewable Energy Grant). Small-scale projects will be greatly benefited by cash grants as this type of incentive allows projects to offset construction costs. In New York, biomass projects installed by low-income homeowners may qualify for an Assisted Home Performance Grant. Single-family homeowners may qualify for a grant of up to $5,000. Buildings with 2-4 units may qualify for grants of up to $5,000 without the necessity of providing income verification of the tenants. However, if the tenants qualify based on their income, the building can receive a grant of up to $10,000. (DSIRE, New York Incentives). Part of the costs can be covered by loan programs sponsored by NYSERDA or other entities.
Accelerated Depreciation Schedules	Accelerated depreciation schedules (ADS) allow businesses to recover investments sooner by permitting a larger deduction of the capital investment during the first year of the investment. In short, ADS provides greater depreciation deductions, eases debt burden and shortens payoff periods. For energy projects, the federal government has in place a Modified Accelerated Cost-Recovery System (MACRS) and authorizes bonus depreciation in some cases. If the energy investment qualifies for the accelerated depreciation schedule, the taxpayer can deduct 50% of the capital investment of the property during the first two years. The remaining 50% of the investment is depreciated over an ordinary depreciation schedule. (DSIRE, Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation (2008-2009)). ADS is appropriate for energy projects with sufficient tax liability to take advantage of the tax benefits afforded. However, small-scale projects might not be able to take full advantage of this type of incentive.
Loan Guarantees	Under a loan guarantee programs the federal or state government or a private entity acts as the guarantor of a monetary obligation (i.e. a loan). This implies, that if the borrower defaults in his obligation to pay the loan, the guarantor would respond for such payments. In the energy sector, loan guarantees are intended to reduce technology risk associated with innovative energy technologies and encourage early commercial use of new or significantly improved technologies in energy

	projects. At the federal level, the Department of Energy (DOE) has established a loan guarantee program for energy projects located in the United States that employ a new or significantly improved technology for the generation of energy and that avoid, reduce or sequester air pollutants and/or emissions of greenhouse gases.
Utility Purchase Mandates/Renewable Portfolio Standard, Renewable Energy Credits	Utility purchase mandates in the form of a renewable portfolio standard (RPS) require utilities to generate a certain percentage of electricity from renewable sources or account for the use of renewable energy with renewable energy credits (RECs). In an RPS system, RECs represent the environmental benefits or attributes of the use of renewable energy. New York State adopted an RPS of 24 percent by 2013 for renewable energy. (DSIRE, New York Renewable Portfolio Standard). In general, RECs are tradable commodities. However, in New York, there is no open market for RECs. All RECs must be purchased by NYSERDA.
Cap and Trade Renewable Energy and Energy Efficiency Set Aside Allowances	On cap and trade systems, a specific number of emissions allowances may be set aside to be awarded to renewable energy and energy efficiency projects. These set-aside allowances provides additional value stream to renewable energy and energy efficiency projects by providing a set percentage of auction revenues to support projects.
Emissions Offsets (ERC)	Emissions offsets allow electricity generating units (EGU) to fund alternate projects that reduce emissions of greenhouse gases and use the reduction in greenhouse gases attributed to these projects to “offset” their own greenhouse emissions, thereby neutralizing their operation. In other words, offsets compensate for reduction or avoidance of emissions that would have been emitted and act as a compensating equivalent to emissions reductions made at a specific source.
Voluntary REC	Voluntary RECs refer to energy credits bought by consumers who want to use renewable energy to supply their electricity needs. Voluntary REC market enables customers to buy renewable electricity from their utility or buy a REC from a broker to account for the use of renewable energy. (Lori Bird, Interaction of Compliance and Voluntary Energy Markets, October 2007, NREL) Note that the RECs bought by utilities to meet mandatory RPSs are referred to be in the compliance market as opposed to the voluntary market.

Significant Modifications to Federal Incentives in the American Recovery and Reinvestment Act of 2009
In addition to unprecedented increases in appropriations for government clean energy related programs, ARRA also included notable new and modified tax incentives targeting clean energy that could directly impact how renewable projects such as biomass are financed. Specifically, ARRA provides multi-year extension the production tax credit (PTC), allows PTC eligible technologies to elect the investment tax credit (ITC) instead, and allows projects to forego the ITC and instead elect a cash grant from the U.S. Treasury of equivalent value. It also removes the double-dipping penalty formerly triggered by the use of “subsidized energy financing.” ARRA also expands the federal loan guarantee program to cover commercial rather than just innovative “non-commercial” projects.

In the case of open-loop biomass systems covered in this guide, these modifications are quite material. The optional 30% ITC is significantly more valuable than the current available PTC for open-loop biomass.[77]

[77] Closed-loop biomass refers to dedicated energy crops. All other biomass feedstocks are considered “open-loop” biomass.

Open-loop biomass systems are currently eligible for only half the PTC value that closed loop biomass and other renewable energy systems can claim.[78]

Calculating the Pro-Forma

From the information described above, the forecasted annual cash flows or a pro-forma can be calculated. Various tools are available to calculate energy costs and savings based on the data described above. These include spreadsheet and software models developed by government agencies and private industry. These tools are helpful in conducting scenario analyses to address the risk factors identified in the cross-cutting finance chapter of the guidebook.

Illustrative Example Assessment of Biomass Project Economic Viability

This section will use both simple payback and DCF/NPV methods to evaluate a simple hypothetical biomass project.

Simple Payback

The projected savings and required investment of a potential biomass project are shown in the following table. To simplify the analysis, only the major costs and savings are shown. They include energy costs (electricity savings and fuel costs), non-fuel operations and maintenance costs, and installation costs. In an actual project evaluation, it is important to capture the savings or revenues from all value streams. Factors that affect savings include baseline electricity costs (demand and energy charges), ability to sell/price for export power, other utility costs (standby charges), total fuel costs, fuel consumption, operations and maintenance costs, hours of operation, load factor, and the value of thermal energy.

Sample Projected Annual CHP Saving

Current Annual Purchased Electricity Costs	$1,600,000
Current Annual Fuel Costs	$900,000
Baseline Total Annual Costs	$2,700,000
Projected Annual Purchased Electricity Costs	$240,000
Projected Annual Biomass Fuel Costs	$900,000
Projected Annual Additional O&M Costs	$90,000
Projected Total Annual Costs	$1,230,000
Projected Annual Energy Savings	$1,470,000
Projected Annual REC Revenue Streams	$195,000
TOTAL SAVINGS/REVENUE	$1,665,000
Investment Costs	$12,000,000
30% Investment Tax Credit/Treasury Grant	($3,600,000)
TOTAL INVESTMENT	$8,400,000
Simple Payback	5.0 years

[78] The full PTC was $21/MWh and escalates 2% per year. Open loop biomass systems are eligible to receive half of the PTC, $10.5/MWh. Very few closed-loop biomass systems operate in the U.S.

This project has a simple payback period of just over five years. Depending on the customer, this may or may not meet the payback cutoff hurdle. It should be noted that this example project relies heavily on renewable energy incentives to achieve this marginal payback.

Discounted Cash Flow/Net Present Value

In order to evaluate the net present value of the project the projected annual cash flows for the entire life of the project need to be considered. The projected cash flows of the same project for the 15 year life of the project are shown in the following table. Projections for future electric and fuel prices are assumed. These assumptions are usually based on local biomass feedstock suppliers, public information/forecasting models, in-house price forecasting, or historical data. The company considering the project uses a nominal discount rate of 7.5% to reflect the internal cost of capital.

Table 24. Sample Biomass Annual Cash Flows ($000) and NPV.

	YEAR														
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Energy Savings[1]	1,470	1,499	1,529	1,560	1,591	1,623	1,655	1,689	1,722	1,757	1,792	1,828	1,864	1,902	1,940
Revenue from RE Incentives[2]	195	199	203	207	211	215	220	224	228	233	238	242	247	252	257
Total Net Annual Cash Flow	1,665	1,698	1,732	1,767	1,802	1,838	1,875	1,913	1,951	1,990	2,030	2,070	2,112	2,154	2,197

Intalled Costs[3]	(8,400)	NPV	7,538
Annual Discount Rate	7.5%		

1. Includes net electricity purchases, net biomass fuel costs, and additional O&M related to the biomass project
2. Includes REC net revenue stream
3. Costs are net 30% ITC

Based on the projected cash flows, this project has a net present value of $7,538,000. This positive value indicates that it is preferable to the current situation and should be pursued if no other capital investment being considered has a higher NPV.

Other Considerations

In many cases there are other potential value streams associated with a well-designed project that are difficult to quantify in a traditional economic assessment, but should be considered in the investment decision. They include but are not limited to:

- Improved reliability of energy service
- Potential independence from the grid if project is CHP
- Improved productivity of core business processes if feedstock is a waste product of the host industrial process
- Potential sale of ancillary services to utility or transmission operator

The value of these benefits depends on the characteristics of the customer, energy use patterns, electric utility, and regulatory environment.

APPENDIX E: GLOSSARY

1-Hour Ozone Area
The surface ozone concentration in parts per billion backward averaged over –one hour.

8-Hour Ozone Area
The surface ozone concentration, in parts per billion backward averaged over – eight hours.

2009 American Recovery and Reinvestment Act - ARRA
An act signed into law on February 17, 2009, designed to jump-start the economy. The Act was a response to the recession and global economic crisis of 2008-2009. It includes measures to modernize the nation's infrastructure and enhance energy independence.

Adsorption
The condensation of gases, liquids, or dissolved substances on the surfaces of solids.

Anaerobic Digester
An enclosed system designed to optimize naturally occurring anaerobic bacteria to accelerate decomposition of the feedstock.

ASTM E 1528
A tool for identifying and current or past potential environmental concerns at low-risk sites.

Attainment Area
Any area that meets the national primary or secondary ambient air quality standard for a pollutant.

British Thermal Units - BTUs
The amount of heat energy needed to raise the temperature of one pound of water by one degree F.

Brownfield Site
A parcel of land, the use or development of which may be complicated by the presence of pollution or hazardous materials from a previous use. Frequently, brownfields are abandoned industrial sites.

Buffer Zone
An area of land separating two different zones or areas to help each blend more easily with the other, such as a strip of land between industrial and residential areas.

City Environmental Quality Review – CEQR
New York City's requirement that a proposed project incorporate consideration of environmental factors early in the planning, review, and decision-making processes of local government agencies.

Combined Heat and Power - CHP
The production of electricity and thermal energy from a single fuel source. CHP systems are frequently described as capturing the waste heat from electricity production, which dramatically increases fuel efficiency.

Comprehensive Environmental Response, Compensation, and Liability Act - CERCLA
Federal law that provides a federal "superfund" to clean up uncontrolled or abandoned hazardous-waste sites as well as accidents, spills, and other emergency releases of pollutants and contaminants into the environment.

Comprehensive Plan
A general plan to control and direct the use and development of a large piece of property. Towns frequently adopt a municipal comprehensive plan for the development and preservation of land and resources within the town. General goals set forth in a municipal comprehensive plan are supposed to be supported by the municipality's zoning ordinance.

Construction and Demolition Waste (C&D)
Waste building materials, dredging materials, tree stumps, and rubble resulting from construction, remodeling, repair, and demolition of homes, commercial buildings, and other structures and pavements.

Cyclone Burner
A type of combustion system requiring fuel of 3.5 mm maximum size and a 12% maximum moisture content.

Debt Financing
Taking a loan or issuing a bond to provide capital.

Digestate
Post-digested solids from an agricultural digester.

Dry Basis (D.B.)
Fuel moisture calculated as the percentage difference between the wet weight of the fuel and the dry weight of the fuel, relative to the dry weight.

Emission Reduction Credits (ERCs)
Government credits issued when an air pollution source, such as a boiler, reduces its emissions of nonattainment pollutants. ERCs are bankable for current and future use and can be bought and sold in emission trading markets.

Endogenous
Occurring inside the body.

Environment Assessment Form (EAF)
A form used by an agency or municipality to assist it in determining the environmental significance or nonsignificance of a contemplated action.

Environmental Impact Statement (EIS)
A document that provides a means for agencies, project sponsors and the public to systematically consider the potential environmental impacts of a contemplated development project. An EIS facilitates the weighing of social, economic and environmental factors early in the planning and decision-making process, and includes proposed alternatives and mitigation measures.

Environmental Site Assessment (ESA)
A desktop review, based on previous uses of a site, performed as a preliminary environmental risk assessment of sites/operations that are to be purchased. The ESA can help identify any latent environmental exposure that may come with the property. Also referred to as environmental screening analysis, preliminary risk analysis and/or preliminary site assessment.

Equity Financing
Financing by an investment partner or partners, who will in return receive shares of ownership in, and/or revenue from, the project being financed.

Extraction turbine
A steam turbine equipped with an opening through which partly expanded steam is bled at one or more stages.

Farm-Financed Model
Model of agricultural digester financing that places the burden of financing on the farm hosting the digester. Usually a project developer is employed to design and construct the system.

Feedstock
Raw materials that may be treated or converted to create fuels. Biomass feedstocks in New York include forestry products, crop residues, municipal waste streams, manure and food processing waste.

Fluidized Bed Combustion
A combustion system that burns fuel, in the form of small particles, in a hot bed of granular material, such as sand. Air is blown up from underneath, so that combustion takes place in turbulent suspension. At operating temperatures, the fuel and granular bed behave as a fluid.

Fuel
Processed feedstocks that have been pretreated and are ready for combustion, such as pre-sized or dried wood chips.

Genset
A distributed generation system; an electricity generator located in proximity to the end user. Many gensets are CHP units.

Grate (Stoker) System
Combustion system using an automatic feeder to distribute fuel onto a grate, where it burns.

Greenfield Site
A site being developed for the first time.

Greenhouse Gas (GHG)
A gas, such as carbon dioxide, methane, or ozone, that contributes to global warming (also known as "the greenhouse effect").

Hazardous Air Pollutant (HAP)
Pollutants that are known to cause or are suspected of causing cancer or other serious health effects, such as developmental problems or birth defects.

"Home Rule" State
A state that largely delegates land use regulation to local municipalities. New York is a home rule state.

Investment Tax Credit (ITC)
A credit subtracted from one's total tax liability, designed to spur investment in types of projects the government wishes to support. ITCs are available for investment in certain types of renewable energy projects.

Joint Venture (JV)
A business undertaking by two or more persons engaged in a single defined project.

Load Profile
A measure of the time distribution of a building's energy requirements, including the heating, cooling, and electrical loads.

Low-Grade Forest Products
Less valuable wood harvested by loggers as a side-product. After selling their high-value saw logs and veneer-logs, loggers may sell the remaining low-grade wood, including tree tops and less desirable types of trees, to wood brokers, who process it to create wood fuels, mulch and other products.

Major Source
Any stationary source or group of stationary sources that emits or has the potential to emit at least 10 tons/year of any hazardous pollutant or 25 tons/year of any combination of hazardous air pollutants.

Microturbine
Small combustion turbines, approximately the size of a refrigerator, with outputs of 25-500 kW.

Mixed Municipal Waste
Municipal solid waste that has not been sorted into specific categories (such as plastic, glass, wood, etc.)

National Ambient Air Quality Standards (NAAQS)
Nationwide outdoor air quality standards established by the U.S. EPA.

Net Metering
For electric customers that generate their own electricity, net metering allows for the flow of electricity both to and from the customer – typically through a single, bi-directional meter. Net metering allows excess electricity generated on-site to be sold back onto the grid.

New Source Performance Standard (NSPS)
Uniform national EPA air emission and water effluent standards that limit the amount of pollution allowed from new sources or from modified existing sources.

New York State Pollution Discharge Elimination System Permit (SPDES)
Permit that regulates point source discharges to groundwaters and surface waters in New York.

Nonattainment Area
Any area that does not meet the national primary or secondary ambient air quality standards for a pollutant.

Nongovernmental Organizations (NGOs)
An organization that pursues an issue or issues of interest to its members by lobbying, persuasion, and/or direct action, but has no participation or representation by any government.

Non-Recourse Financing
A loan secured by the project itself as opposed to some other type of collateral.

Notice of Intent (NOI)
A form required by NYDEC for stormwater discharge from a construction site. Any site qualifying for coverage under the SPDES General Permit for construction must submit a NOI form in order to obtain permit coverage.

Offset Source Area
The area from which emissions offsets may be obtained. Refers to a method used in the 1990 *Clean Air Act* to give companies that own or operate large emissions sources in nonattainment areas flexibility in meeting overall pollution reduction requirements when changing production processes. Emissions of criteria air pollutants may be increased if an offset (reduction of a somewhat greater amount of the same pollutant) is obtained.

Opportunity Fuels
Fuels that are not commonly used but are available in a particular geographical area, thus representing an opportunity for alternative fuel use in that area.

Organic Rankine Cycle (ORC)
A Rankine cycle process that uses an organic, high molecular mass working fluid having a lower boiling point than water.

Oxidative stress
Increased oxidation leading to proliferation of free radicals that cause cell damage.

Parlor Waste
Manure and other waste from the floor of the milking parlor in a dairy operation.

Pile Burner
A type of combustion system in which fuel is burned in a pile. Pile burners typically consist of cells, each having an upper and lower combustion chamber.

PM2.5:
Fine particles, less than 2.5 microns in diameter, linked to heart and lung disease in humans.

Potential To Emit (PTE)
The total emissions that a facility would release by operating at a maximum load for 24 hours per day and 365 days per year.

Power Purchase Agreement (PPA)
A long term contract between a generator of electricity and a purchaser of electricity.

Process Emissions
Emissions from industrial processes other than combustion.

Production Tax Credit (PTC)
A federal tax credit for electricity generated using eligible renewable energy resources.

Pro-Forma Financial Statement
A financial statement prepared on the basis of assumed events and transactions.

Pulverized Biomass Combustion
A mixture of fuel and primary combustion air is injected into the combustion chamber. Combustion takes place while the fuel is in suspension and gas burnout is achieved after secondary air addition.

Pyrolysis
A process during gasification when the carbonaceous material heats up, releasing volatiles and producing char.

Rankine Cycle
A closed-loop thermodynamic cycle, and the basis for standard steam turbine operation.

Reactive Oxygen Species (ROS)
Ions or very small molecules including oxygen ions, free radicals and peroxides, and characterized by an unpaired electron, which makes them unstable.

Renewable Energy Credit (REC)
A credit representing the positive environmental attributes of renewably-generated electricity. For example, RECs may represent avoided emissions.

Renewable Portfolio Standard (RPS)
A law requiring utilities to generate a certain percentage of their electricity using renewable resources. New York State is one of a number of states that has adopted an RPS.

Solid Waste Management Plan (SWMP)
A plan for the collection, transportation, treatment, and disposal of solid waste.

Special Use Permit
A permit to use a property in a manner identified as a special exception by a zoning ordinance.

Staged Combustion Design
A combustion system using two or more chambers to combust the fuel in different phases.

State Environmental Quality Review Act (SEQRA)

A New York State act requiring all state and local government agencies to consider environmental impacts during decision-making. Most, if not all, biomass projects of the types covered in this guidebook will be subject to the SEQRA process.

Steam Turbine
A reciprocating engine driven by steam.

Stormwater Pollution Prevention Plan (SWPPP)
A plan to prevent pollution due to stormwater runoff during construction.

Suspension Burner
A combustion system that burns fuel particles in suspension, using forced air to create a turbulent environment. Requires fuel in the form of pulverized fine particles 6 mm in diameter or smaller and having a maximum moisture content of 15%.

Synthetic Gas (syngas)
A combustible gas produced by biomass gasification, composed largely of carbon monoxide and hydrogen.

Tax Equity Investments
A type of investment by individuals seeking to reduce their tax obligations by using Investment Tax Credits or Production Tax Credits available from qualifying renewable energy projects.

Thermal Offtake Agreement
Agreement to sell heat, usually in the form of steam or hot water.

Type I Action
An action that meets or exceeds specified SEQRA thresholds, and is therefore likely to have an adverse effect on the environment, such that an environmental impact statement will be required.

Type II Action
One of a number of specifically listed actions that are categorically deemed to have no significant impact on the environment, or that are otherwise precluded from environmental review under SEQRA.

Ultra Fine Particles (UFPs)
Particles less than 1 micron in diameter, linked to heart and lung disease in humans.

Uniform Procedures Act (UPA)
A state act governing the administration of applications for permits submitted to NYSDEC or its agents within the state.

Unlisted Action
Actions that are not listed as Type I or Type II under SEQRA.

Updraft Gasifier
A type of gasifier in which fuel enters the gasification chamber from above, falls onto a grate and forms a pile. Air from below the grate is blown up through the fuel pile.

Wet Basis (W.B.)
Fuel moisture calculated as the percentage difference between the wet weight of the fuel and the dry weight of the fuel, relative to the wet weight.

Whole Tree Burner
A closed-loop biomass system designed to combust entire trees or tree segments up to 20 feet in length.

Zoning Variance
A license or official authorization to depart from a zoning law.

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Guide for Siting Small-Scale Biomass Projects in New York State

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