Final Report

Assessing the Benefits and Costs of Anaerobic Digester CHP Projects in New York State
ASSESSING THE BENEFITS AND COSTS OF ANAEROBIC DIGESTER CHP PROJECTS IN NEW YORK STATE

by:
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Abstract:

Although several anaerobic digestion (AD), biogas utilization, and co-digestion projects have been successfully commissioned in recent years, many potential New York State (NYS) sites remain undeveloped or underdeveloped. According to previous New York State Energy Research and Development Authority (NYSERDA) surveys, approximately 14-17 water resource recovery facilities (WRRFs) in NYS currently use biogas for power generation, with approximately three WRRFs using co-digestion to increase gas production. Another 37 WRRFs reported that they are either flaring or using their biogas only in a boiler.

This project presents the results of one-on-one interviews with wastewater utility staff to document factors that drive biogas energy projects forward and those that hold them back. While some utilities reported that the biggest hurdle to implementing cost-saving, renewable energy is a perception of “inadequate payback,” many others faced local obstacles related to lack of outside funding, pressing demands for limited capital, and utilities’ own decision-making processes.

Actual feasibility studies for projects that moved forward and projects that stalled were reviewed to consider whether the assumptions used in the studies were overly conservative. This review found that overly conservative financial feasibility assumptions have not been a significant factor in preventing financially attractive biogas projects from moving forward. Instead, the projects that do not move ahead appear to struggle with the adverse economic effects of small-scale, low local electrical rates, and ancillary digestion project capital costs.

Actual WRRF electrical bills were also analyzed to determine if state electrical tariff structures limit the ability of WRRFs to achieve expected electrical savings from biogas combined heat and power (CHP) projects. This analysis found substantial local variations in NYS electrical rates with consumption charges ranging from $0.03 to $0.12 per kilowatt-hour (kWh) and demand charges ranging from $4 to $49 per kilowatt (kW). When outages for maintenance cause loss of demand savings, facilities with low consumption charges and high demand charges will achieve lower savings from CHP systems. The research team’s analysis estimated a nearly threefold reduction in estimated electrical savings from an example 750 kW CHP system in plants with very low consumption portions of their electrical structure.

Benefits:

♦ Documents the unique, local nature of biogas project decisions.
♦ Notes opportunities to increase consistency and accuracy in financial evaluations.
♦ Suggests approaches for documenting environmental and grid impacts so that all projects take credit for these legitimate societal benefits.

Keywords: Barriers, biogas, energy, combined heat and power, CHP.
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<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>AD</td>
<td>anaerobic digestion</td>
</tr>
<tr>
<td>ARRA</td>
<td>American Recovery and Reinvestment Act</td>
</tr>
<tr>
<td>BCA</td>
<td>benefit/cost analysis</td>
</tr>
<tr>
<td>BEGWS</td>
<td>Bath Electric, Gas and Water Systems</td>
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<tr>
<td>CEF</td>
<td>Clean Energy Fund</td>
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<tr>
<td>CEIP</td>
<td>Clean Energy Incentive Program</td>
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<tr>
<td>CES</td>
<td>Clean Energy Standard</td>
</tr>
<tr>
<td>CFA</td>
<td>Consolidated Funding Application</td>
</tr>
<tr>
<td>CFR</td>
<td>Code of Federal Regulations</td>
</tr>
<tr>
<td>CH₄</td>
<td>methane</td>
</tr>
<tr>
<td>CHP</td>
<td>combined heat and power</td>
</tr>
<tr>
<td>CIP</td>
<td>capital improvement program</td>
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<tr>
<td>CO</td>
<td>carbon monoxide</td>
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<tr>
<td>CO₂</td>
<td>carbon dioxide</td>
</tr>
<tr>
<td>CO₂e</td>
<td>carbon dioxide equivalent</td>
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<tr>
<td>Con Edison</td>
<td>Consolidated Edison</td>
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<tr>
<td>CPP</td>
<td>Clean Power Plan</td>
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<tr>
<td>DER</td>
<td>distributed energy resource</td>
</tr>
<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
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<tr>
<td>EBMUD</td>
<td>East Bay Municipal Utility District</td>
</tr>
<tr>
<td>ECM</td>
<td>Energy Conservation Measure</td>
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<tr>
<td>eGRID</td>
<td>Emissions and Generation Resource Integrated Database</td>
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<tr>
<td>EPA</td>
<td>Environmental Protection Agency</td>
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<tr>
<td>EPRI</td>
<td>Electrical Power Research Institute</td>
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<tr>
<td>ESCO</td>
<td>energy service company</td>
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<tr>
<td>EUI</td>
<td>electric utility infrastructure</td>
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<tr>
<td>FEMA</td>
<td>Federal Emergency Management Agency</td>
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<tr>
<td>FOG</td>
<td>fats, oils, and grease</td>
</tr>
<tr>
<td>ft³</td>
<td>cubic foot/feet</td>
</tr>
<tr>
<td>GHG</td>
<td>greenhouse gas</td>
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<tr>
<td>HSW</td>
<td>high-strength waste</td>
</tr>
<tr>
<td>HVAC</td>
<td>heating, ventilation, and air conditioning</td>
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<tr>
<td>IOU</td>
<td>investor-owned utility</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>SO\textsubscript{x}</td>
<td>oxides of sulfur</td>
</tr>
<tr>
<td>TBL</td>
<td>triple bottom line</td>
</tr>
<tr>
<td>VSD</td>
<td>volatile solids destruction</td>
</tr>
<tr>
<td>WEF</td>
<td>Water Environment Federation</td>
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<tr>
<td>WERF</td>
<td>Water Environment Research Foundation</td>
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<td>WE&amp;RF</td>
<td>Water Environment &amp; Reuse Foundation</td>
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<tr>
<td>WPCP</td>
<td>water pollution control plant</td>
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<tr>
<td>WRRF</td>
<td>water resource recovery facility</td>
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EXECUTIVE SUMMARY

ES.1 Purpose
Despite significant financial and programmatic support from the New York State Energy Research and Development Authority (NYSERDA), relatively few New York State (NYS) wastewater utilities move forward with anaerobic digestion (AD) and biogas utilization projects.

Roughly 16 of the 22 NYS water resource recovery facilities (WRRFs) that are 20 million gallons per day (mgd) or larger have existing AD facilities and would be candidates for enhanced biogas utilization projects. Two other midsize facilities are currently migrating from incineration to digestion and biogas utilization.

AD and biogas utilization projects can take several forms, including:
- Upgrading existing AD facilities to include biogas utilization via combined heat and power (CHP), vehicle fuel, or pipeline injection.
- Upgrading existing AD facilities to accept imported feedstocks for additional energy production.
- Installing new AD facilities in WRRFs that currently use other solids disposal methods.

The investigation presented in this report builds on previous Water Environment Research Foundation (WERF) findings with a focus on AD projects that include beneficial biogas utilization. Specifically, the work scope was developed to address the following questions:
- What makes AD projects attractive?
- What drives the economics of AD projects?
- Are sufficient benefit/cost analysis (BCA) tools available and used by wastewater utilities?
- Which risk factors are prominent and what are potential means to overcome those risks?
- Can environmental benefits be monetized through incentives?
- Based on current conditions, what are the best financing/funding approaches for municipal wastewater utilities pursuing biogas utilization projects?
- Are there regulatory or other barriers that might be changed or other features that NYS government could employ to further reduce hurdles to wastewater biogas projects?

ES.2 Methods
The study used the following approaches to gather relevant information:
- Interviews were conducted with 13 wastewater utility representatives regarding their experiences with AD and biogas feasibility studies and project execution.
- Billing data from 13 WRRFs were analyzed to identify tariff provisions that might impact the level of actual electrical savings that CHP systems achieve relative to projected savings based on average cost per kilowatt-hour (kWh) values.
- Actual feasibility studies for four projects that moved forward and four projects that stalled were reviewed to consider whether the assumptions used in the studies were overly conservative.
- Literature reviews were used to obtain background on state, federal, and electrical utility policies that affect AD and biogas projects.
ES.3 Findings

The following features appear to be prominent in making AD projects attractive to wastewater utility management:

- **Minimizing waste:** Biogas utilization projects are widely recognized as an opportunity to minimize biogas flaring and use a “wasted” resource.
- **Rate neutrality:** Most utility staff appear to be open to biogas projects that at least break even on a life-cycle basis so that they do not put upward pressure on rates.

Although many utility staff viewed biogas project risks as manageable, utility decision makers noted the following risks:

- **Economic factors:** Within the projects reviewed for the study that did not move forward, most were stalled by lack of economic feasibility.
- **Biogas quantity:** Some plants expressed concern about whether they would have enough biogas to ensure project viability, because of either low plant flows or uncertainty in organic feedstock procurement.
- **Staffing:** Some plants expressed concerns about whether operations and maintenance (O&M) requirements would undermine project financial viability, divert staff from other functions, or be higher than expected because of union contract provisions.

Interviews with plant staff found that many other utilities faced locally specific obstacles unrelated to these risks. These obstacles included lack of outside funding, pressing demands for limited capital, and competing municipal priorities. While not all local obstacles can be mitigated, the following sections summarize approaches to improve project feasibility, and to improve the quality of benefit/cost information used in go/no go decisions.

**Addressing Electrical Tariff Provisions That Erode CHP Project Savings**

Review of plant electrical bills found a wide range of electrical rate structures as a result of NYS’s deregulated marketplace. Some plants were found to have electrical rates that are high enough to promote economic feasibility for CHP projects. However, many municipalities have been able to purchase generation and delivery services at very competitive rates, which benefits WRRFs by reducing operating costs but reduces their ability to cost-justify biogas CHP projects.

Beyond the generalized issue of low electrical rates, other electric tariff provisions can positively or negatively affect CHP savings. Understanding these provisions is important to improving savings estimate accuracy. Because biogas CHP systems provide greater availability and load stability than many other renewable technologies, there may be opportunities to negotiate with electrical generation and distribution entities to obtain rate structures that are more supportive of CHP systems. Published guidance for the wastewater industry could assist with these negotiations. Relevant tariff provisions considered in the billing review include:

- **High demand charges as a percent of electrical costs:** This issue is relevant to CHP systems because plants lose demand savings when they have outages, for either planned maintenance or unplanned failures. Seven of the 13 plants had demand charges that accounted for over 40% of their bill, which reduces their likely CHP electrical savings relative to plants whose bills are dominated by $/kWh charges. In absolute terms, the demand charges varied from $3 per kilowatt (kW) to $49/kW. Some ESCO entities don’t even count...
demand savings when they project electrical cost savings because it is difficult to predict how many months will have outages or other circumstances that increase the demand kW.

- **High fixed charges:** Fixed monthly charges cannot be offset by onsite power generation because they are not tied to billed kilowatts or kilowatt-hours, so high fixed charges can erode CHP savings. Fixed charges ranged from 0.0% to 3.5% in the study.

- **Standby fees:** Although no standby fees were found in the NYS billing records, some states allow electrical utilities to charge distributed energy resource (DER) entities standby fees. These fees are collected every month based on the generator size, and are intended to reflect the electrical utility’s cost to provide standby grid power when the DER is off line.

- **Minimum demand charges:** These charges allow the electrical utility to look back 12 to 18 months and charge based on either the current month’s demand or the “minimum billing.” These types of ratcheted minimum demand charges can also erode CHP savings by limiting ongoing demand savings if a high demand is established during an outage or prior to CHP startup.

**Leveling the Playing Field with Other Renewable Energy Sources**

As large-scale wind technology has advanced and solar panel prices have fallen, electrical utilities have found it more cost-effective to fulfill their state renewable portfolio obligations (e.g., NYS Clean Energy Standard [CES]) using these technologies rather than providing meaningful financial incentives to WRRFs operating biogas CHP systems.

Biogas projects differ from most other large-scale renewable projects in that the produced power is almost always consumed behind the meter to serve the large, 24/7 electrical load at the WRRF. Some states have pursued approaches to capture the non-monetary value of this renewable energy by increasing the value of biogas CHP electrical savings beyond the savings realized through reduced electrical consumption. For example, advocates in California have introduced legislation to make biogas power consumed behind the meter eligible for renewable energy credits (RECs).

In a variation on this approach, Wisconsin used to promote an external sales program in which wastewater utilities exported all of their biogas power. The electrical utilities paid a premium price for this renewable energy, while the WRRF continued to purchase all of its consumed power at market rates. However, this program has waned because electrical utilities are no longer willing to pay significant premiums for this biogas power because they can purchase wind and solar renewable energy at very low rates.

NYS may wish to consider similar approaches to keep biogas CHP competitive with other renewable generation. A biogas-specific premium incentive would be conceptually similar to the NYS Affordable Solar program that provides increased financial incentives to projects that address the public policy objective of increased access to renewable power in low-income communities.
Using Standardized BCA Calculations to Improve Feasibility Evaluations

A review of feasibility studies completed by consulting engineers found that overly conservative financial feasibility assumptions have not been a significant factor in preventing financially attractive biogas projects from moving forward. Instead, the projects that do not move ahead appear to struggle with the adverse economic effects of small-scale, low local electrical rates, and ancillary digestion project capital costs.

Based on this feasibility study review, it is also clear that there is a need for tools and methodologies that incorporate full cost accounting principles and present accurate conclusions in a standardized, credible way. Existing spreadsheet tools (NYSERDA microgrid BCA and WERF Life Cycle Assessment Manager for Energy Recovery [LCAMER]) provide useful starting points for a standardized BCA approach. The industry would benefit from merging the strengths of these two tools and addressing the following “gap” areas:

♦ **Economic evaluations**: Significant opportunities exist to improve the accuracy of these estimating tools by providing technical guidance for engineers calculating site-specific natural gas costs or savings, electrical demand savings, and O&M costs. These values need to be tailored to each WRRF’s seasonal heat demands, demand tariff structures, plant size, biogas contaminant concentrations, and the current loading of the CHP system relative to 100% capacity.

♦ **Full cost accounting**: The reviewed reports often failed to capture and articulate the non-monetary and non-standard system benefits, including greenhouse gas (GHG), nitrogen oxides (NOₓ), and oxides of sulfur (SOₓ) emission reductions through reduced fossil fuel electrical generation, reduced GHG emissions from landfilling of organic wastes, low-cost waste treatment for local wet industries, lower peak demand, avoided distribution losses, and associated generation infrastructure needs. These benefits were often not estimated, estimated incorrectly, or not considered in decision making. The NYSERDA microgrid BCA has a comprehensive approach to calculating and, importantly, monetizing most of these factors so that they can be readily included in the decision-making process.

♦ **Alternative biogas technologies**: As biogas-to-vehicle fuel and pipeline injection alternatives become more common as either alternatives or adjuncts to CHP systems, financial and monetized benefits calculations must be tailored to incorporate potential benefits and costs from these technologies. In addition, many researchers are working on technology platforms to create even higher-value chemical commodities or liquid transportation fuels from biogas. Future programs may need to accommodate this broader context.

♦ **Microgrid context**: Some wastewater facilities may wish to consider using a microgrid approach to that considers how the biogas CHP system integrates with other renewable and standby power sources. However, several important technical considerations must be addressed in order to realize resiliency benefits from biogas CHP projects.
Financing and Funding Approaches to Allow Good Projects to Move Forward

Several plants contacted for this study stated that their projects would move forward if they received financing or other monetary assistance. Appropriate financing methods could include:

- **Capital cost support**: Utilities expressed interest in funding approaches that reduced their capital cost contribution in order to reduce their exposure to financing costs that could impact rates if savings fall short of expectations.
- **Alternative delivery**: Some utilities appear to be successfully using energy service company (ESCO) delivery methods. ESCO performance guarantees are used to mitigate financial risk for biogas projects. ESCO and third-party financing is available as an alternative to bonding or state financing for energy projects, but does not appear to be widely used.
- **Phased implementation**: Phased implementation can reduce the initial capital cost, allow wastewater utilities to pursue their energy goals incrementally, and reduce exposure to project creep.

In addition, federal or state subsidies comparable to the investment and production tax credits used by private entities to develop wind and solar projects would increase the attractiveness of biogas CHP projects. This approach has already started to shift biogas market interest toward vehicle fuel projects because of the significant economic incentive created by marketable credits under the federal Renewable Fuel Standard (RFS) legislation.
CHAPTER 1.0

INTRODUCTION

The goal of this report is to answer the following questions:

♦ What makes anaerobic digestion (AD) projects attractive?
♦ What drives the economics of AD projects?
♦ Are sufficient benefit/cost analysis (BCA) tools available and used by wastewater utilities?
♦ Which risk factors are prominent and what are potential means to overcome those risks?
♦ Can environmental benefits be monetized through incentives?
♦ Based on current conditions, what are the best financing/funding approaches for municipal wastewater utilities pursuing biogas utilization projects?
♦ Are there regulatory or other barriers that might be changed or other features that New York State (NYS) government could employ to further reduce hurdles to wastewater biogas projects?

1.1 Research Context

Previous research has found that the biggest hurdles to implementing cost-saving, renewable biogas energy projects are perception of “inadequate payback,” more pressing demands for limited capital, and utilities’ own decision-making processes (WERF, 2012). The following sections summarize the findings of related research on biogas market potential and NYS policies affecting biogas projects.

1.1.1 Previous Estimates of NYS Biogas Market Potential

Earlier studies have characterized the market for additional power generation from wastewater biogas in NYS (NYSERDA, 2007 and WERF, 2015). Figure 1-1 depicts the size and location of New York WRRFs with AD. According to previous surveys, approximately 14 to 17 WRRFs in NYS currently use biogas for power generation, with approximately three of these WRRFs using co-digestion to increase gas production. Another 37 reported that they are either flaring or using their biogas only in a boiler (including approximately nine WRRFs larger than 75 mgd in rated capacity and seven WRRFs in the 20-75 mgd range).

WRRFs that do not have digestion and that appear to be landilling raw solids would be candidates to install AD and beneficial biogas utilization facilities. According to survey data, the Niagara Falls, Baldwinsville-Seneca Knoll, and Mamaroneck WRRFs appear to be landilling raw solids (WERF, 2015).

In addition, a few NYS wastewater utilities have historically incinerated solids, and are moving toward new AD systems with associated biogas utilization projects.
1.1.2 Estimates of National Biogas Market Potential

The U.S. Environmental Protection Agency’s (EPA’s) Combined Heat and Power (CHP) Partnership conducted an analysis of the market potential for CHP at WRRFs based on a state-by-state evaluation of the cost of power, cost to produce biogas power, and number of WRRFs with under-utilized biogas (EPA, 2011). This study concluded that nation-wide, approximately 257 WRRFs have economic potential for CHP, with a potential capacity of 178 megawatts (MW) based on digestion of sludge only, without consideration of additional potential capacity through implementation of co-digestion. This number represents approximately 43 to 63 percent of the sites that were considered to have technical potential. Most sites with economic potential were large WRRFs (greater than 30 mgd) because these facilities could take advantage of economies of scale.

1.1.3 Biogas Market Potential: Wisconsin Example

The Wisconsin Office of Energy Innovation recently released a report that explores barriers to increased deployment in that state’s biogas industry (OEI, 2016). As expected, insufficient revenue generation was cited as one of the primary barriers, along with a need for effective operations and maintenance (O&M) procedures. This report notes several examples of
projects that did not emerge from the planning stage or were shut down following changes in state energy regulations that reduced energy buyback rates. This buyback system formerly encouraged electrical utilities to buy renewable power directly from WRRFs at a premium rate in order to fulfill their renewable portfolio obligations. As an example, the Janesville, Wisconsin, WRRF was able to obtain a 10-year buyback contract with its electrical utility in 2010 that pays it $0.12 per kilowatt-hour (kWh) for on-peak power and $0.075/kWh for off-peak power, but it does not anticipate that these attractive rates will remain available when the contract expires in 2020. In addition, recent Wisconsin utility rate cases have begun undermining the value of power consumed “behind the meter.” Refer to Section 3.2 for additional discussion of how various aspects of rate structures can affect CHP savings.

1.1.4 Previous WERF State Policy Comparison

A recent WERF study included a comparison of state policies in NYS, California, and Georgia (WERF, 2015). The intent of this study was to contrast policies that helped or hindered biogas CHP projects, as well as energy efficiency and onsite solar projects. NYS’s state policies affecting biogas CHP were found to be generally comparable with California’s and more supportive than Georgia’s. Specific policies that were compared include:

- **Renewable portfolio standards (RPS):** Both NYS and California include digester gas as an eligible renewable energy source, so biogas-generated power can be used to meet state RPS requirements, although the NYS program has since expired (refer to Section 2.1.1 for current program). Georgia has no RPS or voluntary goals.
- **Power purchase agreements (PPAs) and energy performance contracting:** California and NYS both allow PPAs, but Georgia does not. All three states allow energy service companies (ESCOs).
- **Interconnection limits:** For very large projects, interconnection limits can come into play. NYS’s interconnection limit was recently raised from 2 to 5 MW, but is still lower than California’s 10 MW limit.
- **Air quality regulations:** NYS is progressive in crediting useful thermal output when considering permitted CHP emissions.

1.2 Project Overview

This section presents the research objectives, scope, and approach of this project, as well as the organizational structure of the report.

1.2.1 Research Scope and Approach

The focus of this research was to document factors that affect the progress of biogas projects, especially at WRRFs with New York State Department of Environmental Conservation (NYSDEC)-rated flows equal to or greater than 5 mgd. WRRF staff were interviewed to capture project-specific experiences, including:

- Recent experience with biogas utilization feasibility studies.
- Financial metrics used to determine whether projects would move forward.
- Experience with third-party entities such as ESCOs and their role in advancing projects.
- Other organizational decision-making issues, including competition for capital spending.

Table 1-1 provides contextual information regarding the utilities that provided information for this study. Because some of the wastewater utility staff contacted for this project
indicated that the information shared by WRRF staff might be sensitive for various reasons, the WRRFs referenced in this report are assigned a number and are not identified by name or specific plant parameters.

### Table 1-1. Participating WRRF Summary.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Rated Plant Size (mgd)</th>
<th>Existing AD</th>
<th>Biogas Utilization&lt;sup&gt;a&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>WRRF 1</td>
<td>20-75</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
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<td>5-20</td>
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<tr>
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<td>Yes</td>
</tr>
<tr>
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<td>5-20</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>WRRF 5</td>
<td>5-20</td>
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</tr>
<tr>
<td>WRRF 6</td>
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</tr>
<tr>
<td>WRRF 7</td>
<td>&gt;75</td>
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<td>No</td>
</tr>
<tr>
<td>WRRF 8</td>
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<td>&gt;75</td>
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<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>WRRF 11</td>
<td>&lt;5</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>WRRF 12</td>
<td>&gt;75</td>
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<td>Yes</td>
</tr>
<tr>
<td>WRRF 13</td>
<td>5-20</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>WRRF 14</td>
<td>5-20</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>WRRF 15</td>
<td>20-75</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>WRRF 16</td>
<td>&gt;75</td>
<td>Yes</td>
<td>No</td>
</tr>
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</tr>
<tr>
<td>WRRF 20</td>
<td>5-20</td>
<td>No</td>
<td>No</td>
</tr>
</tbody>
</table>

<sup>a</sup> As of October 2016.

Because financial viability is such a significant factor in moving a project forward, this topic was explored further through a review of cost and savings assumptions used in feasibility reports and a review of actual WRRF bills to determine if tariff structures undermine savings.

### 1.2.2 Report Organization

This report is divided into the following chapters that document the methodology used to collect data and the findings in various focus areas:

- Chapter 1.0: Introduction
- Chapter 2.0: State and Federal Policies
- Chapter 3.0: Electrical Utility Policies
- Chapter 4.0: Non-Monetary Benefit/Cost Analysis
- Chapter 5.0: Wastewater Utility-Level Decision Making
- Chapter 6.0: Conclusions
CHAPTER 2.0

STATE AND FEDERAL POLICIES

Energy projects generally, and biogas utilization projects specifically, are affected by a web of policies, rules, and regulations promulgated by various governmental bodies, each with differing and potentially conflicting policy objectives (Figure 2-1). This chapter reviews some of the federal and NYS policies in place at the time of this research that affect biogas CHP projects. In addition, examples of state policies to support CHP in other states are highlighted.

Figure 2-1. Multiple Regulatory Entities and Processes Affecting Biogas Energy Projects.

2.1 Federal Policies Impacting Biogas Utilization

Few federal policies directly affect biogas projects, with the exception of EPA’s Renewable Fuel Standard (RFS) which incentivizes biogas projects that produce vehicle fuels (Code of Federal Regulations [CFR] Title 40 Part 80). As noted below, other federal energy policies are not specifically applicable to most wastewater utility biogas projects.

2.1.1 Renewable Fuel Standard

The RFS program has effectively monetized the benefits of renewable vehicle fuels via the Renewable Identification Number (RIN) incentives. RINs are sold by the biogas producer (WRRF) via a broker and bought by petroleum companies. RIN incentives classify biogas-derived vehicle fuels as “cellulosic,” which is therefore more competitive and valuable than other renewable fuels such as corn-derived ethanol in the market-based RIN trading system (Willis, 2015). Although the value of RINs fluctuates because they are sold in an open market, a typical value at the time of this research was $1.80 (per gallon of ethanol gas equivalent). There are 1.7 gallons of ethanol per gallon of diesel of gas, or approximately $3.00/gallon of diesel equivalent.

2.1.2 EPA Clean Power Plan

This section describes the EPA Clean Power Plan (CPP), including state compliance provisions and the Clean Energy Incentive Program (CEIP).

State Compliance Provisions

The CPP establishes state-specific interim and final goals for each state, based on these limits and each state’s mix of power plants. Although implementation of the CPP has been stayed by the U.S. Supreme Court, NYS has been supportive of the plan and is crafting policy to
meet the CPP’s interim goals. The allowable role of biomass sources in fulfilling CPP requirements appears to be still under consideration by the EPA.

**Clean Energy Incentive Program**

The CEIP was included in the final EPA CPP. The CEIP was designed to help states meet their carbon reduction goals under the plan by encouraging early investments in zero-emitting renewable energy generation, and by removing barriers to investment in energy efficiency and solar measures in low-income communities. The CEIP provides a matching pool of allowances and emission rate credits to states and tribes that choose to participate. Unfortunately, biogas is not listed among the zero-emitting renewable energy technologies that will be eligible because the program was targeted toward “jump-starting” wind and solar projects (EPA, 2016).

2.1.3 **Investment and Production Tax Credits**

Currently, only biogas projects that generate electricity are eligible for a production tax credit under Section 45 of the federal tax code. Legislation was recently introduced that would extend the credit to other energy uses like production of pipeline-quality natural gas and compressed renewable natural gas vehicle fuel. In addition, the most recent federal renewable energy bill provided a much shorter extension of credits for biomass projects, for now extending the program only until December 31, 2016 (Coker, 2016). These credits are available as a corporate tax credit so they are useful to private developers but are seldom used directly by municipal wastewater utilities.

2.2 **NYS Policies**

Various NYS policies and regulatory approaches positively or negatively affect the ability of AD and biogas utilization projects to move forward.

2.2.1 **Tax Cap**

One utility cited the tax cap legislation as a hurdle because it limits its ability to pursue capital projects because of the potential for project financing to trigger a rate increase. The tax cap limits the amount by which local governments can increase property taxes to the lower of 2 percent or the rate of inflation. This hurdle suggests a potential role for third-party financing or energy performance contracting in order to develop of biogas utilization projects while mitigating the risk of sewer rate impacts.

2.2.2 **Environmental Regulation: Approval for Emerging Wastewater Treatment Technology**

A recent WERF study of trends in energy use in NYS WRRFs found that many WRRFs had taken advantage of newer technology such as high-efficiency blowers, innovative energy recovery, and light-emitting diodes (LED) to reduce their energy use. However, one facility (WRRF 17) expressed frustration with regulatory conservatism regarding NYSDEC’s refusal to support its plans to install an enhanced primary clarification technology that had been successfully pilot-tested in another NYS WRRFs and was expected to have a beneficial effect on their biogas production.

2.2.3 **Environmental Regulation: Air Quality Requirements**

Exhaust gas treatment, increasingly required in urban settings, causes higher project capital costs and operating complexity because continuous effective removal of siloxanes is required to avoid damaging exhaust catalysts. In addition to traditional pollutants of concern
(nitrogen oxides [NOₓ] and carbon monoxide [CO]), regulations limiting emissions of air toxics can also trigger catalyst requirements.

### 2.2.4 Organics Management: Landfill Bans

Organics management policies, including legislation intended to divert food waste from landfills, can impact WRRF AD projects by providing a large supplemental source of digestion feedstock to increase biogas production. Previous WERF research compared the carbon footprint of food waste management alternatives, including landfill, compost, WRRF via sewers, hauling to WRRF AD facilities, and mixed-materials recovery (WERF, 2012). This study found that hauling food waste for WRRF AD provided a significant greenhouse gas (GHG) emission reduction relative to other alternatives.

The New York City Commercial Organics Law, which took effect in July 2015, bans landfilling of organic waste from commercial entities above a certain disposal size. The commercial organics regulation does not currently apply to the rest of NYS, but the NYS legislature is considering future measures.

Other nearby states are also advancing legislation to curtail landfilling of organic wastes. As an example, Connecticut passed Public Act 11-217, which targets commercial operations and is phased-in, contingent on the development of organics recycling facilities. Less than six months after Connecticut’s second organics recycling facility establishes service, waste generators must source-separate. For waste generators that have a permitted recycling facility within 20 miles that can accept their material, their organics must be recycled. Likewise, Massachusetts enacted a commercial food waste disposal ban in 2014, but AD facilities for food waste have been slow to develop in response to the ban, despite state incentives.

### 2.2.5 Microgrid

In 2015, NYSERDA launched an initiative known as the “NY Prize” to provide financial support for communities that wanted to use stand-alone microgrid energy systems that can operate independently in the event of a power outage. Microgrids can combine renewable energy inputs, including CHP systems at WRRFs. The intent of this program is to reduce costs, promote clean energy, and build reliability and resiliency into the electric grid. At the time of this research the Bath Electric, Gas, and Water Systems (BEGWS) was completing the initial study phase of local microgrid feasibility as part of the NY Prize, with biogas CHP at its WRRF playing a central role.

### 2.3 Policy Strategies Adopted by Other States

Other states are also working to support increased use of CHP in WRRFs, as well as in other settings. A few examples of relevant policy strategies and reference documents are presented below.

#### 2.3.1 California: Integrating Onsite Generation into Utility Planning

The EPA recently published a report titled, “Energy and Environment: Guide to Action” that summarizes state policies and best practices for advancing energy efficiency, renewable energy, and CHP (EPA, 2015). This reference notes that electrical utility planning is an opportunity to examine non-traditional electricity resources such as CHP with the same rigor as traditional generation resources. For example, in California, utilities must prepare an onsite generation forecast as part of their long-term procurement plans. Onsite generation, of which...
CHP is a subset, must also be considered as an alternative to distribution system upgrades by California’s investor-owned utilities (IOUs).

2.3.2 California: Proposed Legislation Enabling REC Value for Renewable Energy Consumed behind the Meter

The California Association of Sewer Agencies sponsored legislation that would allow power generated by biogas and consumed within a WRRF to be eligible to participate in the California renewable energy credit (REC) market. Although this legislation has not yet been passed, this approach could provide a useful mechanism for providing additional support for wastewater biogas projects.

2.3.3 Massachusetts: CHP Incentives

According to a recent interview with Amy Barad (Cogeneration Channel, 2015), Massachusetts provides several types of support for biogas CHP. Production incentives available to biogas CHP owners include:

- Sale of renewable energy certificates to electrical utilities for compliance with the Massachusetts RPS standard.
- Sale of certificates for alternative energy production (biogas facilities can qualify for both credits).
- Virtual net metering, which can be used if facilities export power. Unused net metering credits can be assigned to another customer, with the value nearly equal to the retail electrical tariff rate.
- Rebates for CHP facility construction, which may be available through electrical utility companies.
- Grants offered by the Massachusetts Clean Energy Center for project feasibility studies, as well as for design and construction costs.

2.3.4 Maryland: Aggregate Net Metering

The Maryland Public Service Commission recently granted a request from a major wastewater utility to allow it to “wheel” excess biogas-power production between facilities. NYS currently allows aggregate net metering only for solar power. Aggregate net metering would be attractive to NYS facilities that anticipate reaching or exceeding net zero energy status, or facilities with remote digestion and CHP.

2.3.5 Minnesota: CHP Action Plan

The Minnesota Commerce Department received a U.S. Department of Energy (DOE) grant to convene a stakeholder engagement process that examined the issues affecting both renewable and natural-gas-fueled CHP deployment in Minnesota. This process involved more than 250 participants, including wastewater utility representatives, who collaborated to develop policy recommendations. Key issues that emerged from this process are summarized in Table 2-1.
Table 2-1. Priority Areas and Action Items Identified by Minnesota’s CHP Action Plan.

<table>
<thead>
<tr>
<th>Priority Areas</th>
<th>Action Items</th>
<th>Strategies</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP evaluation methodology and criteria</td>
<td>Establish uniform CHP energy savings attribution model and project evaluation criteria</td>
<td>Establish a Technical Reference Manual (TRM) subcommittee to consider supply-side efficiency technologies, including review of CHP model approaches, including from other states</td>
</tr>
<tr>
<td>Mapping CHP opportunities</td>
<td>Map CHP opportunities at WRRFs and public facilities</td>
<td>New DOE-funded project mapping WRFF opportunities</td>
</tr>
<tr>
<td>Education and training opportunities</td>
<td>Leverage existing financing program applicable to CHP</td>
<td></td>
</tr>
<tr>
<td>CHP ownership problems and solutions</td>
<td>Leverage existing financing programs applicable to CHP</td>
<td>Address state regulation that currently does not clearly support electrical utility ownership of CHP on customer sites</td>
</tr>
<tr>
<td>CIP CHP supply-side investments</td>
<td>Examine electric utility infrastructure policy</td>
<td>CIP electric utility infrastructure (EUI) provisions potentially could be adapted and expanded to support CHP deployment</td>
</tr>
<tr>
<td>Standby rates</td>
<td>Continue discussion through PUC’s generic proceeding</td>
<td>Establishing a generic proceeding on standby rates to ensure fair, effective, and transparent standby policies</td>
</tr>
</tbody>
</table>
CHAPTER 3.0

ELECTRICAL UTILITY POLICIES

This chapter summarizes the impact of several commercial and regulatory aspects of the NYS electrical industry on WRRF biogas projects:

- Interconnection standards and resulting capital and engineering costs
- Net metering policies that limit savings for WRRFs with power production that exceeds their onsite consumption
- Competitive market structures that can reduce electrical savings
- The impact of planned and unplanned outages on demand charges and CHP system electrical savings

This chapter also presents an analysis of actual WRRF electrical bills to determine whether unexpected charges might have an adverse effect on electrical savings.

3.1 Regulatory Issues

This section describes regulatory issues that affect WRRF biogas utilization projects, including interconnection standards, net metering standards, and the structure of the NYS electrical market.

3.1.1 Clean Energy Standard (CES)

In August 2016, the New York Public Service Commission (PSC) adopted the CES, which replaces and builds on the expired NY RPS, with an ultimate goal of 50% renewable energy by 2030. The CES establishes a year-by-year timeline with increasing targets for deployment of new large-scale renewable resources. The CES includes biogas from anaerobic digestion and landfill sources among the eligible renewable power resources.

Unlike the previous NYS RPS program, the compliance requirements have been assigned to the L Serving Entities (LSEs), including investor-owned distribution utilities, ESCO Community Choice Aggregation programs, and self-supplying customers through the New York Independent System Operator (NYISO). Under Tier 1 of the CES, LSEs will procure new RECs under a procurement program administered by NYSERDA.

3.1.2 Reforming the Energy Vision (REV)

REV is a collaborative effort by the NY PSC, NYSERDA, New York Power Authority (NYPAA), and Long Island Power Authority (LIPA) to “create strategies for a clean, resilient and more affordable energy system, while actively spurring energy innovation, bringing new investments into the State, and improving consumer choice” (http://rev.ny.gov/). REV programs that may be relevant to WRRFs pursuing biogas projects include:

- **Demonstration projects**: REV demonstration projects are geared toward programs with the potential to lower costs, test advanced technologies, and design new replicable business models. This program would not support individual biogas CHP projects, but conceivably could come into play as part of a larger, innovative partnership arrangement.
- **Clean energy financing**: The NY Green Bank portfolio of the REV Clean Energy Fund (CEF) partners with private financial institutions to accelerate and expand the availability of
capital for clean energy projects. In some cases, this program may provide an adjunct to the municipal bonding and state revolving fund financing for WRRF biogas projects.

- **Technical assistance:** Under the CEF Investment Plan, the “REV Connect” program will offer a central forum for distributed energy resource (DER) providers to submit project ideas and receive expert guidance, feedback, and facilitation, and will match ideas with customers, communities, potential partners in the market, and utilities. Similar to the demonstration projects, the REV Connect’s focus on partnerships and innovative business models appears to limit the applicability of the program for standalone biogas projects at WRRFs.

### 3.1.3 Interconnection

Expedited and uniform processes for gaining electrical utility approval for modifying plant electrical distribution systems to accept CHP generated power can lower project costs and procedural barriers. Proper design of this interconnection to avoid adverse effects on the grid power supply is a crucial concern for both WRRFs and electrical utilities.

NYS first adopted uniform interconnection standards in 1999 and the Standard Interconnection Requirements (SIR) have subsequently been amended several times. Amendments were made to the SIR in March 2013 to simplify and expedite the interconnection application and review process. The most recent amendments were made in March 2016, which increased the maximum interconnection capacity from 2 MW to 5 MW.

The SIR rules now apply to systems connected in parallel with the distribution system located in the service area of one of NYS’s six investor-owned local electric utilities: Central Hudson Gas & Electric, Consolidated Edison (Con Edison), New York State Electric and Gas Corporation, Niagara Mohawk (d/b/a National Grid), Orange and Rockland Utilities, and Rochester Gas and Electric.

The processes covered by the SIR extend from the initial inquiry to final utility acceptance for interconnection and include interconnection timelines, responsibility for interconnection costs, and procedures for dispute resolution.

### 3.1.4 Net Metering Standards and Sales of Excess Power

For most WRRFs considering conventional biogas CHP projects without co-digestion, the CHP system can be expected to provide 25-45% of WRRF electrical demand. As WRRFs become more efficient and implement aggressive co-digestion programs, they may increase this percentage beyond the “net zero” status and be able to derive income from excess power that is exported to the grid. For example, one NYS plant has secured an agreement with their local power company to export excess power outside of the net metering regulations. Exported power from the WRRF is reimbursed at a rate of $0.025 to 0.040/kWh.

The value for excess electricity depends on the mechanism for its sale and the extent of monetization of its attributes. For some WRRFs with excess electricity generation, nearby industries or municipal facilities can allow for small micro-grid arrangements that would be mutually beneficial. For most facilities, the value for the excess electricity is a function of applicable State laws, tariffs and programs.

In recent years, net metering tariffs enabled some small renewable power generators to “bank” excess power generation by exporting to the grid during periods when DER production exceeded behind-the-grid consumption. However, NYS net metering cannot be expected to
benefit power generation at WRRFs. Current net metering law restricts eligibility for biogas renewable power to farm-based systems. Additionally, the net metering approach is being phased out in the State. Under REV, the NYS Department of Public Service (DPS) has been engaging stakeholders in the Value of Distributed Energy Resources (VDER) proceeding (Case 15-E-0751) to develop value stack tariffs to phase out the current net metering tariffs. The proposed value stack would be higher than the typical rate paid for excess power delivered to utilities.

The new value stack approach may bring some additional value for electricity generated at WRRFs. Although the Phase One value stack tariffs would initially cover only the renewable power systems that are currently eligible for net metering, the collaborative process will be developing concepts that can be expected to be applied in future tariffs that would be applicable to renewable generation at WRRFs.

Elements of the currently proposed Phase One value stack approach do limit the future potential for improved revenues for WRRFs. The DPS staff proposal would allow application of the value stack rate only to power exported to the grid. For WRRFs that will use all the power they generate on site, the higher value stack rate paid for excess power would have no benefit and savings would continue to reflect the offset of retail electrical purchases. However, the higher rate can be important for facilities digesting other organics and producing excess electricity. Additionally, many stakeholders have filed comments on the Staff proposals including requests to allow application of the environmental value stack element to power generation used on site. Incorporation of this change in the final Commission Order would increase the value of all power generated, regardless of where it is used.

The forthcoming Clean Energy Standard (CES) Program could also provide value for Renewable Energy Credits (REC) associated with biogas-fired power generation at WRRFs. WRRFs with new biogas CHP systems (installed or upgraded after January 1, 2015) could bid into the CES auctions administered by NYSERDA or market the REC to their utility or other parties. Although the final provisions of the CES Program have not been established, the WRRF may be able to market RECs associated with all biogas generation, including RECs associated with the electricity used on site as well as the exported electricity.

While these tariff and REC Program approaches are being finalized, it is difficult for single projects to project cash flows and use these estimates to obtain debt financing. Participation in the proceedings for finalizing these may bring benefits to the WRRF sector, particularly since Public Service Commission is completing its decisions with multiple opportunities for stakeholder input and collaboration.

### 3.1.5 NYS Electrical Market Structure

The NYS electrical market has undergone deregulation. Through this process, electricity-generating capacity formerly owned by investor-owned utilities was sold to independent power producers. Now, this generating capacity is traded in a competitive wholesale electricity market operated by the NYISO. Under this system, NYS WRRFs have separate billings from two entities for electrical generation and distribution. This aspect of NYS regulations can be a barrier to advancing CHP systems because some WRRFs have negotiated very competitive rates with their providers, which undermines the ability to derive savings from biogas CHP systems. Refer to Section 3.2.5 for additional discussion of this topic.
3.2 Impact of Tariff Provisions on CHP Electrical Savings

Table 3-1 shows the major components of current NYS electrical generation and distribution bills.

<table>
<thead>
<tr>
<th></th>
<th>Distribution</th>
<th>Generation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed account charges</td>
<td>$/month</td>
<td>Commodity costs</td>
</tr>
<tr>
<td>Demand charges</td>
<td>$/kW</td>
<td>Demand charges (uncommon)</td>
</tr>
<tr>
<td>Delivery charges based</td>
<td>$/kWh</td>
<td></td>
</tr>
<tr>
<td>on use</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Systems benefits charge</td>
<td>$/kWh</td>
<td></td>
</tr>
<tr>
<td>Taxes</td>
<td>% of bill</td>
<td></td>
</tr>
</tbody>
</table>

a. Typically based on highest 15-minute period during the billing month.

Electrical tariffs and rate structures in NYS vary by region and power supplier. In order to explore the range of impacts for various WRFF electrical customers, billing statements were analyzed to identify whether certain tariff provisions had the potential to significantly erode expected electrical savings from WRFF CHP systems under typical operating conditions. Bills were analyzed for 13 WRFFs, three of which had operating CHP systems. The following sections highlight the significant aspects of these bills and how savings for an example CHP project would vary under WRFF-specific billing scenarios.

3.2.1 Demand Charges

CHP systems are subject to output interruptions for planned or unplanned maintenance. Oil changes are a frequent planned maintenance activity, occurring four to eight times per year. Gas treatment systems are typically maintained two to three times per year. In months with output interruptions, the billed demand (kW) is likely to be higher, even if the outage is of short duration and the monthly CHP production (kWh) is not significantly reduced, as illustrated by Figure 3-1.

Demand charges varied from 8% to 77% of total WRFF electrical expenditures among the WRFF sites reviewed for this study. Locations with high demand charges are at greater risk of poor savings if CHP systems are offline for planned or unplanned maintenance, especially if the CHP system provides a significant fraction of the WRFF’s power. This impact can be reduced (but not eliminated) through the following approaches:

- Install modular generator capacity (e.g., several microturbines) so some capacity can remain in service while other units are offline.
- Schedule maintenance for off-peak or low diurnal electrical demand periods.
- Schedule engine and gas treatment maintenance during the same outage.
- Operate standby diesel generators during biogas CHP maintenance (if allowed by air permit hourly operating limits).
Figure 3-1. Example of Monthly Electrical Use Variations and Determination of Demand Charge.
Note: Assumes single 175 kW CHP unit with continuous output, except during outages.
3.2.2 Other Relevant Tariff Provision and Rate Features

In addition to demand savings, the following tariff provisions can impact CHP savings:

- **Seasonal rate variations:** Some WRRF rates appear to change by season, most often with higher rates during winter months.

- **Competitive electrical contracts:** As stated previously, NYS has a competitive market for purchased power. Several WRRFs appear to have negotiated very reasonable contracts for generated power, as seen in the billing summary in Table 3-1.

- **Monthly minimum charges:** In some cases, electrical utilities have instituted a partial “ratchet” demand structure. Under this system, CHP maintenance outages in 1 month can set a higher monthly minimum charge for the following months unless the WRRF takes steps to curb electrical demand during the CHP outage. For example, in one location the minimum demand charge is 75% of the highest kilowatt amount billed in the previous 12 months.

3.2.3 Electrical Bill Analysis

Table 3-2 summarizes the distribution and generation charges for the facilities that provided billing data. WRRFs 6, 7, 8, 9, and 11 all had relatively high unit demand charges, which were balanced by relatively low consumption charges. Demand charges were significantly variable on a monthly basis for several WRRFs, presumably because these facilities are exposed to seasonal and short-term electrical market rate fluctuations. Addition of CHP power generation at these facilities would help to stabilize the WRRF’s month-to-month electrical costs.

Unique to WRRFs 8 and 9 is the monthly minimum demand charges noted above. For the data period analyzed, WRRF 8 was billed on the calculated minimum value 54% of the time and WRRF 9 was billed on the calculated minimum value 23% of the time.
Table 3-2. Comparison of Demand and Consumption Rates and Comparison of Estimated Savings Calculation Approaches.

<table>
<thead>
<tr>
<th>Item</th>
<th>Unit</th>
<th>WRRF 1</th>
<th>WRRF 2</th>
<th>WRRF 3</th>
<th>WRRF 4</th>
<th>WRRF 5</th>
<th>WRRF 6</th>
<th>WRRF 7</th>
<th>WRRF 8</th>
<th>WRRF 9</th>
<th>WRRF 10</th>
<th>WRRF 11</th>
<th>WRRF 12</th>
<th>WRRF 13</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand (kW) charges as percent of total monthly electrical billings</td>
<td>%</td>
<td>8</td>
<td>69</td>
<td>46</td>
<td>18</td>
<td>18</td>
<td>57</td>
<td>56</td>
<td>53</td>
<td>50</td>
<td>19</td>
<td>77</td>
<td>12</td>
<td>12</td>
</tr>
<tr>
<td>Unit demand charges</td>
<td>$/kW</td>
<td>4</td>
<td>11</td>
<td>6</td>
<td>3</td>
<td>7</td>
<td>31</td>
<td>30</td>
<td>31</td>
<td>26</td>
<td>10</td>
<td>49</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Unit consumption charges</td>
<td>$/kWh</td>
<td>0.07</td>
<td>0.04</td>
<td>0.12</td>
<td>0.06</td>
<td>0.08</td>
<td>0.04</td>
<td>0.04</td>
<td>0.05</td>
<td>0.05</td>
<td>0.07</td>
<td>0.03</td>
<td>0.06</td>
<td>$0.05</td>
</tr>
<tr>
<td>Total blended cost</td>
<td>$/kWh</td>
<td>0.08</td>
<td>0.06</td>
<td>0.13</td>
<td>0.07</td>
<td>0.09</td>
<td>0.09</td>
<td>0.09</td>
<td>0.09</td>
<td>0.10</td>
<td>0.10</td>
<td>0.14</td>
<td>0.07</td>
<td>$0.06</td>
</tr>
</tbody>
</table>

Comparison of estimated monthly savings:  a,b,c

| Separate demand ($/kW) and consumption ($/kWh) | $    | 39,000 | 23,000 | 63,000 | 33,000 | 40,000 | 33,000 | 32,000 | 39,000 | 37,000 | 37,000 | 40,000 | 31,000 | 29,000 |
| Blended average ($/kWh)                         | $    | 41,000 | 30,000 | 65,000 | 36,000 | 44,000 | 44,000 | 41,000 | 45,000 | 47,000 | 48,000 | 70,000 | 33,000 | 31,000 |

a. Assumed reduction in the peak demand charges for 5 months per year.
b. 90% uptime was assumed for credit from the energy production. Predicted average savings were calculated in two ways
c. Hypothetical 750 kW engine-generator.
3.2.4 Impact of Site-Specific Tariff Rates on CHP Savings and Simple Payback

Electrical savings estimates presented in biogas economic feasibility studies are often based on average blended costs per kilowatt-hour values derived by dividing total annual electrical costs by total annual billed electrical consumption (kWh). On this basis, the average blended electrical costs at the WRRFs reviewed for this study varied from $0.07/kWh to $0.14/kWh.

When consumption (kWh) costs are a large share of billed electrical costs, this estimating method yields a reasonable preliminary prediction of electrical savings. However, as noted above, many NYS WRRFs have high demand charges and low consumption charges. In these cases, a more rigorous estimate of electrical savings should be made based on actual billing structures.

To compare the effect of the variations in electrical rates, Table 3-2 also presents predicted monthly electrical savings for a hypothetical 750 kW engine-generator with predicted savings calculated in two ways. The first approach used the separate unit demand and consumption charges summarized in Table 3-2. The second approach used the overall blended cost per kilowatt-hour produced alone. The savings estimates using the separate approach were lower than the blended approach by 5% to 25%. Although this reduction is relatively modest, it is still important for decision makers to understand the details of how their specific billing rates can influence likely savings, design alternatives, and operating strategies.

The estimated savings presented in Table 3-2 also illustrates the almost three-fold range in estimated savings, depending on regional differences in electrical rates. Locations with low rates may struggle to make their projects economically viable, especially at smaller scales.

3.2.5 Comparison of Billings for Single WRRF with Prolonged CHP Outage

One of the WRRFs in the billing data set had a prolonged CHP outage. The bills for months with and without CHP operation were analyzed to determine whether the extra cost to purchase power to replace the lost CHP production would corroborate the findings of the previous section. This comparison found that the savings realized during months when the CHP system was operating were approximately 20% less than the average cost of power on a $/kWh basis. Because the period considered by this comparison included seasonal and market rate changes, this analysis adjusted the “without CHP” rates to match the average rates during the period when the CHP was operating so that the result would not be skewed by rate changes. For this WRRF with relatively high demand charges, the lower value of energy savings appears to be largely attributable to the inability to reduce demand charges commensurate with generated production, similar to the impact of separate demand and consumption savings estimates described in the previous section.
CHAPTER 4.0

NON-MONETARY BENEFIT/COST ANALYSIS

Previous researchers have organized non-monetary factors under three main headings, which incorporate both the benefits accruing from biogas utilization and those related to land application of biosolids (Elenbaas, 2014). The following costs and benefits were included in the WERF Triple Bottom Line (TBL) Analysis of Biosolids Alternatives and form a comprehensive list of potential non-monetary factors related to AD and beneficial biogas and biosolids utilization:

- Conservation/optimization of resources:
  - Beneficial use of nutrients.
  - Fixed carbon and GHG emissions.
  - Fixed carbon and energy recovery (net energy recovery minus the energy required to harness the energy inherent in the solids).
  - Water conservation (improving water-holding capacity of soils via biosolids application).

- Net impacts on media:
  - Impacts to land/soil quality.
  - Impacts to air quality.
  - Impacts to water quality.

- Meeting future regulatory requirements: projected ability of a biosolids management activity to provide flexibility for potential future changes in air, biosolids, or water quality requirements

This chapter reviews the existing methods and tools used to gauge these benefits, with an emphasis on the benefits associated with biogas utilization, including GHG and air quality benefits. These methods include both tools to quantify the magnitude of benefits and approaches to monetize the benefits.

4.1 Estimating Emissions Reduction Benefits via Marginal Changes

One of the primary environmental benefits associated with biogas utilization is a net reduction in GHG and air pollutant emissions relative to fossil-fuel-based electrical generation. One utility that is actively working to reduce its GHG emissions is concerned that biogas projects would have a diminished GHG impact over time as the regional electrical grid added renewable resources. This is a critical environmental policy issue, so it is important that GHG benefit estimates provide full credit for likely grid system impacts.

The key for analyzing GHG and other air pollutant emissions impacts from biogas generators in the context of the larger power system is that the benefits should be determined at the margin, not at the average (Wakefield, 2010). Using the power system shown in Figure 4-1 as an example, hydro energy tends to be used fully regardless of small changes in grid load; small, distributed energy production will not reduce hydro energy production. The same is true for nuclear energy, which rarely is drawn down from maximum available output, and most renewable resources, which are generally non-dispatchable and rarely curtailed. Consequently,
hydro, nuclear, and renewable costs do not belong in the avoided cost of losses or the estimation of emissions reductions. Almost everywhere, marginal reductions in energy result in marginal reductions in coal and gas consumption, even though the ultimate reduction may occur far from the site of the change and within an entirely different utility.

Estimates of CHP system marginal costs and emission rates are based on the displaced fuel use and emissions from separate heat (boiler) and power (grid) systems. For displaced power production, a proxy unit can be used as a first approximation, for example, a typical combined-cycle gas unit’s heat rate and emissions rates. The benefit may be increased for typical losses from the generation to the distribution level, e.g., a 5.82% grid loss factor for eastern grid (Diem, 2012).

As an example of this approach, the EPA’s CHP Partnership’s CHP Emissions Calculator (https://www.epa.gov/chp/chp-emissions-calculator) uses Emissions and Generation Resource Integrated Database (eGRID) heat rates and fossil fuel emissions factors as the basis to calculate avoided emissions from CHP units (EPA, 2015). The EPA CHP Partnership recommends the use of the fossil fuel output emission rates for displaced grid supplied electricity from a CHP application because CHP units tend to operate on a continuous basis, characteristic of baseload generating units. Therefore, eGRID fossil fuel emission rates are larger than the total output emission rates, which are reduced by renewable generation.

Figure 4-1. Impact of Marginal Changes in Biogas Generation on Electrical Grid.
4.2 Existing Benefit Models

This section describes three existing benefit models, including the EPA CHP Partnership’s Emissions Calculator, WERF TBL analysis of biosolids alternatives, and NYSERDA’s microgrid BCA (https://www.nyserda.ny.gov/All-Programs/Programs/NY-Prize/Resources-for-applicants). The first two tools can be used to estimate and evaluate certain project benefits. The NYSERDA BCA calculates a comprehensive benefit:cost ratio to demonstrate that a project’s benefits outweigh its costs and to allow comparisons of various project alternatives.

4.2.1 EPA CHP Emissions Calculator

As noted above, the EPA’s CHP Partnership’s Emissions Calculator calculates GHG emissions savings and provides an equivalent car metric. The EPA calculator also estimates reduction in the conventional air pollutants NOx and oxides of sulfur (SOx) resulting from the lower emissions rates from newer CHP systems relative to conventional fossil fuel power plants. Because this calculator uses regional data from eGRID, the estimate reflects the power generation mix in the project location.

4.2.2 Triple-Bottom-Line Analysis of Biosolids Alternatives

A spreadsheet tool can help utilities optimize possible economic, environmental, and social benefits through a quantitative TBL analysis (Elenbass, 2014). The tool allows customized weighting of the economic, environmental, and social TBL components as well as the criteria considered under each of the three categories. Results are combined to allow TBL alternative comparisons, as shown in Figure 4-2. Default weighting values are based on an industry survey. The authors highlight the need for the tool to be adjusted based on local context, while noting the danger of biased adjustment of assumptions.

**Figure 4-2. Example WE&RF TBL Evaluation Scoring Results.**
4.2.3 Life Cycle Assessment Manager for Energy Recovery

The Life Cycle Assessment Manager for Energy Recovery (LCAMER) spreadsheet compares the relative economic merits of energy recovery alternatives over the life of the systems (WERF, 2012). The spreadsheet captures capital costs, O&M costs, replacement costs, simple energy savings calculations, and emissions reduction estimates. Economic outputs include the range of possible economic viability criteria, including net present worth, annualized economic cost, simple payback, and internal rate of return.

4.2.4 NYSERDA Microgrid Benefit/Cost Analysis

Similar to AD and CHP projects, microgrid projects have non-monetary benefits that are relevant to advancing deployment. NYSERDA developed a BCA model to assess the monetary and non-monetary benefits and costs of proposed microgrid systems to assist in project ranking for the NY Prize Community Grid Competition (NY Prize). The BCA model categorizes benefits into energy and environmental categories. The benefits in the energy category are items that improve the electrical infrastructure, addressing items previously discussed in Chapter 3.0. However, these energy benefits are noted here for their environmental ramifications.

Energy Benefits

The energy benefits quantified and monetized by this tool that are also applicable to AD and CHP include:

♦ Reduced transmission losses: Similar to the EPA CHP calculator, the BCA model assumes a reduction in demand for electricity, including a factor of 3.2% for typical losses in distribution that are avoided by distributed energy installations, slightly increasing the potential environmental benefits.

♦ Ancillary services-peak load support: The development of distributed generation may defer the need to invest in expansion of the macrogrid’s energy generation, transmission, or distribution systems if the impact of the CHP system on demand for peak capacity can be estimated with reasonable certainty.

♦ Reduction in ongoing macrogrid consumption: The benefit of ongoing consumption reductions is based on forecasts of locational-based marginal energy prices.

Environmental Benefits

The environmental costs and benefits quantified by this tool that are also applicable to AD and CHP at WRRF sites include:

♦ SO₂, NOₓ, and carbon dioxide (CO₂): The BCA model considered the unit emissions factors (tons/MWh) for marginal macrogrid generation, offset by the emissions from the distributed energy generation. The externality value of the net increase (cost) or decrease (benefit) in emissions was estimated based on forecasts of allowance prices ($/ton) for each pollutant. This benefit is partially offset by the capital and ongoing O&M costs that WRRFs will accrue for pollution control equipment such as sulfur removal systems and catalytic exhaust treatment to meet air permit requirements.

♦ Reduced particulate emissions: The BCA benefit of reduced particulate emissions was based on median marginal damage values presented in a report by the Electric Power Research Institute (Wakefield, 2010).

♦ Reduced CO₂ emissions from macrogrid generation: For non-utility sources that are not subject to the emissions caps of the Northeast states’ Regional Greenhouse Gas Initiative, the
net CO₂ benefit was estimated using the marginal damage value estimated in federal reports (Interagency Working Group on Social Cost of Carbon, 2013/2015).

- **Reduced boiler emissions**: While microgrid CHP projects might reduce boiler emissions in locations with fossil fuel boilers, most WRRFs use biogas for hot water boilers, reducing the potential benefit from reduced boiler emissions.

**Resiliency Benefits**

One of the principal benefits of the microgrid approach is an increase in resiliency because power supplied locally and distributed via the microgrid can reduce dependence on the larger electrical grid. The NYSERCA BCA model quantifies these benefits by assessing a cost for power outage impacts affecting local water and wastewater treatment facilities, hospitals and emergency medical services, and police and fire departments. In the past, biogas-fired CHP systems at WRRFs have not been considered to be a credible means of providing resiliency via backup power because of limitations in their ability to “black start” without access to other power sources. In addition, transient voltage conditions associated with large motor starts can cause gas-fired engine-generators to trip off as process equipment is brought back on line. Overcoming these hurdles with integrated CHP/backup power design approaches may provide resiliency benefits to future WRRF-based CHP systems that could be credited in a BCA.

In projects where resiliency is a major project driver, published Federal Emergency Management Agency (FEMA) BCA guidelines provide a useful reference for estimating benefits from reduced risk of wastewater treatment service (FEMA, 2001).

### 4.2.5 Summary of Tools

Each of the benefit models described above takes a different approach and serves differing functions. Table 4-1 summarizes the strengths of each model. Based on this cursory review, it appears that the NYSERDA microgrid BCA effectively captures and monetizes the primary benefits associated with biogas utilization for CHP. Note that none of the utilities interviewed for this study have taken advantage of these tools.

<table>
<thead>
<tr>
<th>Model</th>
<th>Source</th>
<th>Strengths</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHP Emissions Calculator</td>
<td>EPA</td>
<td>Estimates net impact of CHP on GHG and conventional pollutants</td>
</tr>
<tr>
<td>TBL Evaluation of Biosolids Alternatives</td>
<td>WERF</td>
<td>Economic, environmental, and social analysis of biosolids-handling alternatives, with results expressed on a common ranking scale</td>
</tr>
<tr>
<td>Life Cycle Assessment Manager for Energy Recovery</td>
<td>WERF</td>
<td>Standardized life-cycle cost analysis format tailored to WRRF biogas applications</td>
</tr>
<tr>
<td>Microgrid BCA</td>
<td>NYSERDA</td>
<td>Monetized summary of energy and environmental benefits of distributed generation</td>
</tr>
</tbody>
</table>
4.3 Gap Analysis

The tools presented in the previous section provide credible approaches to BCA for WRRF CHP systems. However, the types of benefits covered by these tools have a few gaps. In addition, the tools are not particularly well suited to describing alternative biogas utilization approaches (in lieu of CHP).

4.3.1 Opportunities to Improve Model Accuracy

The NYSRDA BCA model is designed for microgrid systems that include several types of power generation, potentially including wind, solar, and fossil-fueled CHP systems, in addition to biogas CHP systems. The approach to energy savings in this model separates the calculations for fuel savings, electrical generation, and electrical distribution. WRRF savings calculations can be more complex than those included in the microgrid worksheet. In particular, the following savings calculations would benefit from a standard approach that could be included in a future biogas-specific BCA model.

In contrast, the WERF LCAMER model has a specific AD and biogas focus, but a few of its calculations could be more robust. Specific weaknesses of these models include:

♦ **Natural gas savings:** One of the principal benefits of CHP systems in wastewater facilities is their ability to produce both power and heat, serving the year-round thermal demand for digester heating. In northern climates existing biogas boiler systems often also help heat process equipment rooms and other spaces at the WRRF. Diversion of biogas to new CHP systems reduces the amount of heat produced by biogas because CHP systems use roughly 40% of their energy input to produce electricity, leaving around 40% that is recoverable as heat (versus approximately 80% boilers thermal efficiency). If the overall biogas supply is not increased by co-digestion or digester enhancements, WRRFs may see an increase in natural gas expenses to offset this loss in heat generated from biogas. To accurately estimate the net effect of CHP on natural gas consumption, the WRRF heat balance must be calculated on a weekly or monthly basis and compared to the current baseline of natural gas consumption. Neither the LCAMER nor NYSERDA microgrid tool provides a good framework for this calculation. Well-organized, standardized heating calculations would assist engineers in this evaluation and would provide wastewater utilities a clearer picture of projected natural gas costs.

♦ **Demand savings:** Section 3.2.1 discussed the role of demand charges in CHP savings. The LCAMER tool appears to calculate electrical savings strictly on an on-peak/off-peak cost per kilowatt-hour basis, without regard for possible loss of demand savings in months with CHP outages. The “Energy Benefits Calcs” tab in the NYSERDA microgrid tool allows the user to input a “percent of maximum generation capacity benefit realized” and a “percent of maximum distribution capacity benefit realized.” This approach could capture the number of months that the user anticipates a reduction in demand savings because of CHP outages. However, users would need some guidance on how to make a reasonable estimate of this percentage.

♦ **O&M costs – gas pretreatment:** Gas quality varies between WRRFs, with higher levels of contaminants incurring higher gas treatment costs because of more frequent media replacement or regeneration cycles. Gas pretreatment costs are not specifically included in the NYSERDA microgrid tool. The LCAMER tool includes this item, but does not provide guidance on how to modify the default value to suit local conditions.

♦ **O&M costs – CHP equipment:** System size and loading can significantly affect O&M costs, with smaller systems and systems operating at less than 80-90% capacity seeing higher...
O&M costs per kilowatt-hour. Similar to gas pretreatment, the LCAMER tool has a place for user-input $/kWh for CHP equipment O&M, but does not offer guidance on how to assign a reasonable value. The NYSERDA microgrid tool uses fixed ($/rated kW) and variable ($/kWh generated) O&M costs, which better reflects the impact of part-loaded CHP equipment on O&M—sometimes an important issue for systems that will initially be lightly loaded as co-digestion programs are scaled up. No guidance is provided on how to select an appropriate O&M cost based on system size, contracted versus staff labor, and other factors.

4.3.2 Additional Benefits
The following benefits do not appear to be adequately captured by current benefit/cost tools:

♦ **Reduction of GHG emissions from biogas flares:** eGRID considers biogenic fuels such as biogas to have zero net emissions of CO₂, methane (CH₄), and nitrous oxide (N₂O) because the emissions are assumed to be similar to a flare (Diem, 2012). Recent WERF research (WERF, 2012) has provided more detailed fugitive (uncombusted) CH₄ emissions-estimating methods to reflect inefficient combustion in flares caused by flare jet velocity, wind, and low CH₄ fraction. This investigation found that although “default” assumptions of 99% flare efficiency (EPA AP-42) are often used, actual flare efficiency may be several percentage points less. Accounting for uncombusted CH₄ emissions from flares would increase the GHG benefit at WRRFs where CHP installations significantly reduce open flaring of surplus biogas.

♦ **Reduced fugitive fracking methane emissions:** The increased use of fracking technology has substantially lowered the cost of natural gas and led to a significant increase in the use of natural gas for power generation. The U.S. Energy Information Agency is now forecasting that 2016 will be the first year that electrical production from natural gas will exceed electrical production from coal in the United States. While this trend reduces GHG emissions from fossil fuel combustion, several researchers are currently attempting to determine whether fugitive CH₄ emissions from fracking sites are undermining this GHG benefit. Increased utilization of biogas will offset the demand for natural gas and associated fracking emissions.

♦ **Reduced fugitive CH₄ emissions from landfilled organic wastes:** Modern landfills have CH₄ capture systems that contain much of the CH₄ generated by decomposition of organic wastes in landfills, but these systems are not 100% efficient, despite increasingly stringent EPA regulations. A major driver for organic waste bans is the reduction in CH₄ emissions from landfilled waste. AD projects that include food waste diversion will reduce these landfill gas emissions and have a more beneficial GHG impact than comparable composting alternatives because they offset grid power. In addition to GHG benefits, these projects can provide cost-effective, locally based alternatives to other organic waste disposal methods.

♦ **Support for local wet industries:** Anaerobic projects can provide cost-effective and environmentally beneficial waste treatment for local wet industries. As an example, one WRRF closely ties its motivation for a proposed anaerobic project to local economic development because it will collaborate with a proposed new yogurt-manufacturing site.

♦ **Support for adjacent communities and WRRFs:** AD, co-digestion, and biogas utilization are often more cost-effective at larger scales. As such, communities that are willing to accept hauled solids from nearby WRRFs can supplement their own gas production while providing a convenient outlet for solids from smaller facilities.
4.3.3 Non-CHP Biogas Utilization

There is increasing interest in the wastewater industry toward beneficial biogas use as vehicle fuel or for pipeline injection as an alternative to more conventional CHP systems. These biogas alternatives will have different benefits from those presented earlier in this chapter for CHP systems. Some of those benefits are described below:

- **Vehicle fuel**: Biogas used for vehicle fuel reduces GHG emissions by offsetting gasoline use. As noted previously, the EPA RFS regulations have created economic incentives for biogas that is upgraded and used to fuel vehicle fleets. Entities such as large solid waste firms have begun to pursue this biogas model. Other state and provincial entities have alternative programs to promote this approach and commercial. For example, some British Columbia natural gas companies have begun offering consumers the option to buy “green gas” from biofuel sources.

- **Pipeline injection**: Pipeline injection is often used by WRRFs that do not have a compatible local fleet that can use biogas produced for vehicle fuel. Because federal incentives provide a large economic advantage for vehicle fuel, the non-economic factors for pipeline injection are similar to those listed above for vehicle fuel.

- **Heating and boiler use**: In facilities with large seasonal heating demands served by biogas-fueled boilers (e.g., the Onondaga County Metro plant), a CHP retrofit can cause increased natural gas purchases if there is no concurrent increase in biogas from process optimization or co-digestion. In other words, although a biogas CHP system produces heat, it produces approximately half of the heat produced by a boiler fired with the same digester gas flow. The calculations to determine the net increase in seasonal natural gas consumption under the CHP scenario are complex and the financial and environmental costs of potential increased natural gas consumption must be included in the BCA.

- **Engine-driven pumps and blowers**: Non-monetary benefits for engine-driven pumps and blowers are similar to those for CHP. However, most biogas-driven equipment has been replaced or is slated to be replaced with CHP systems, so this scenario is relatively rare and not expected to be an alternative considered for future projects.
CHAPTER 5.0

WASTEWATER UTILITY-LEVEL DECISION MAKING

AD and biogas utilization projects can be stalled by the perception of poor economic feasibility, financial risk, lack of funding or competition for capital, and other local factors; but non-monetary factors are often also prominent drivers. This chapter documents the findings of interviews with NYS wastewater utility staff regarding their project decision-making experiences, including:

♦ Financial viability criteria.
♦ Financial analysis approaches.
♦ Degree of emphasis on non-monetary benefits, including environmental attributes.
♦ Other organizational decision-making barriers.

5.1 Utility Interviews

Fourteen utilities of various sizes were interviewed to gather background on their experiences with pursuing various types of AD and biogas projects. Tables 5-1 and 5-2 summarize the findings of these interviews for projects that are and are not moving forward. Many utilities had conducted detailed feasibility studies and others had only tangentially considered biogas alternatives.

As seen in these tables, the major hurdles and risks identified by interviewed staff were very site-specific. Several utilities mentioned economic considerations, but the context and success criteria varied widely. Economic feasibility hurdles are explored in greater detail in Section 5.2.
Table 5-1. Major Hurdles and Risks Identified by Utilities: Projects Not Currently Moving Forward.

<table>
<thead>
<tr>
<th>Utility and WRRF</th>
<th>Flow (mgd, Rated)</th>
<th>Project</th>
<th>Major Hurdles</th>
<th>Major Risks</th>
<th>Major Drivers</th>
</tr>
</thead>
<tbody>
<tr>
<td>WRRF 16</td>
<td>&gt;75</td>
<td>Heat recovery boiler and steam turbine</td>
<td>Economic feasibility</td>
<td>Heat recovery boiler high pressure, fouling, and corrosion</td>
<td>Electrical production</td>
</tr>
<tr>
<td>WRRF 5</td>
<td>5-20</td>
<td>Biogas CHP</td>
<td>Unexpected additional capital cost for siloxane treatment equipment</td>
<td>Labor-intensive operation</td>
<td>None</td>
</tr>
<tr>
<td>WRRF 4</td>
<td>5-20</td>
<td>Anaerobic industrial HSW digester</td>
<td>Did not receive NYSERDA funding</td>
<td>None identified</td>
<td>Economic development</td>
</tr>
<tr>
<td>WRRF 22</td>
<td>&lt;5</td>
<td>Co-digestion and biogas CHP</td>
<td>Tax cap concerns(^a)</td>
<td>Not enough biogas</td>
<td></td>
</tr>
<tr>
<td>WRRF 17</td>
<td>5-20</td>
<td>Expand biogas heating to main building</td>
<td>Economic feasibility</td>
<td>None identified</td>
<td>Reducing heating costs</td>
</tr>
<tr>
<td>WRRFs 12 and 14</td>
<td>&gt;75</td>
<td>Expand biogas CHP</td>
<td>Economic feasibility</td>
<td>Biogas flow uncertainty, current and future</td>
<td>Increase electrical production</td>
</tr>
<tr>
<td>WRRF 18</td>
<td>5-20</td>
<td>Sludge pipeline to adjacent Rockland digesters for energy production</td>
<td>Solids currently go to County composting, so no economic incentive for wastewater department</td>
<td>Intergovernmental collaboration (Orangetown and Rockland County)</td>
<td>Potential for electrical production</td>
</tr>
<tr>
<td>WRRF 23</td>
<td>20-75</td>
<td>Biogas CHP</td>
<td>Biogas used for drying; not enough remaining biogas for CHP</td>
<td>None identified</td>
<td>None</td>
</tr>
<tr>
<td>WRRF 3</td>
<td>5-20</td>
<td>Upgrade existing digesters and biogas CHP</td>
<td>Public perception concerns with ESCO project delivery(^b)</td>
<td>Minimal perceived risk</td>
<td>Aging equipment</td>
</tr>
<tr>
<td>WRRF 2</td>
<td>5-20</td>
<td>Co-digestion and biogas CHP</td>
<td>City management approval(^c)</td>
<td>Minimal perceived risk</td>
<td>Collaboration with local industry</td>
</tr>
<tr>
<td>WRRF 20</td>
<td>5-20</td>
<td>AD to replace incinerator</td>
<td>Lack of state funding support; CFA process does not provide adequate ranking for funding this project</td>
<td>Minimal perceived risk</td>
<td>Incinerator decommissioning</td>
</tr>
</tbody>
</table>

\(^a\) Refer to Section 2.2.1 for additional background on NYS tax cap.
\(^b\) Public concern was raised by a newspaper article that suggested the ESCO procurement process was not competitive.
\(^c\) Although WRRF staff still strongly support this project, a newly elected city hall official has paused several projects to reconsider city spending priorities.
Table 5-2. Major Hurdles and Risks Identified by Utilities: Projects Moving Forward.

<table>
<thead>
<tr>
<th>Utility</th>
<th>Flow (mgd, Current/Rated)</th>
<th>Project</th>
<th>Major Risks</th>
<th>Major Drivers</th>
</tr>
</thead>
<tbody>
<tr>
<td>WRRF 21</td>
<td>&lt;5</td>
<td>Microgrid, co-digestion and CHP</td>
<td>None listed</td>
<td>Using microgrid to reduce municipal electric utility’s financial exposure to peak pricing for grid power</td>
</tr>
<tr>
<td>WRRF 15</td>
<td>20-75</td>
<td>New AD, co-digestion, and biogas utilization</td>
<td>Quantity of available feedstocks</td>
<td>Landfill organics diversion</td>
</tr>
</tbody>
</table>
5.2 Financial Viability Evaluations

This section presents findings of wastewater utilities financial viability evaluations, including staff perceptions and a review of the economic feasibility analysis.

5.2.1 Staff Perceptions

The most common economic feasibility criterion mentioned by utilities is that CHP projects should be able to provide positive cash flow or at least break even on a life-cycle basis so that they do not put pressure on rates. Other entities cited more conservative “go” thresholds. Table 5-3 summarizes the financial metrics used by utilities that had performed detailed biogas utilization evaluations. This finding coincides with the findings in previous WERF reports (WERF, 2015) that although a break-even project will be considered, utilities prefer to have partial grant funding or more attractive financial metrics as a buffer against project risk.

In addition to the overall financial feasibility criteria mentioned above, there are concerns that ancillary capital costs are not being adequately captured in the feasibility analysis and could ultimately undermine project financial feasibility. These ancillary project costs could include gas treatment, repair of aging digestion equipment, piping cost to connect heat recovery to site heating systems, demolition, and electrical distribution modifications.

Similarly, accurate estimation of ongoing O&M costs is a concern, including engine overhauls, gas treatment, staffing, and exhaust treatment.

Several of the projects included a significant co-digestion component, with projected electrical savings contingent on increased biogas production from cost-effective feedstocks. These utilities expressed concern about financial feasibility being at risk because of uncertainty about long-term availability of (or competition for) organic feedstocks.

5.2.2 Review of Economic Feasibility Analysis

Detailed financial evaluations for projects at seven midsized WRRFs were reviewed to assess how WRRFs are using financial feasibility assumptions and financial “go” thresholds to inform project decisions. The results of this review are shown in Table 5-3, which shows projects that are supported by utility management in the upper rows and projects that were deemed insufficiently attractive in the lower rows. Note that in some cases the green-lighted projects have been stalled by other factors.

Several observations can be made regarding the comparison presented in Table 5-3. The following observations are not intended to constitute a formal critique or quality control review of these financial assessments, but rather to capture the range of approaches currently used by engineering community to assess biogas utilization projects:

◆ No standard financial approach: As might be expected with the range of analysts and entities involved in these analyses, there was considerable variation in the approaches taken to assess the financial viability of biogas utilization. In most cases, simple estimates of annual costs and savings were used to derive either simple paybacks or net cash flow projections. By comparison, the BCA spreadsheet used by NYSERDA for the NY Prize facilitates a standardized life-cycle approach that could easily be modified for use with WRRF projects. WRRF 17 noted in Table 5-3 used this spreadsheet in conjunction with its microgrid application.
Heat savings calculations: As noted in Section 4.3.1, heating calculations for plants in northern climates need to reflect weekly or monthly variations in heat demand for digestion and heating, ventilation, and air conditioning (HVAC) loads in order to determine the net impact of CHP on natural gas purchases. The approach to calculating natural gas savings or costs varied between feasibility analyses. Some of the more comprehensive approaches were difficult to follow and may not have accurately estimated future natural gas costs. As stated previously, this is a non-trivial component of the economic feasibility calculations and warrants a standardized calculation approach.

Capital costs: Capital cost estimates were higher for the projects that did not move forward, but capital costs are difficult to assess and compare because some projects include ancillary projects such as enhanced digester mixing and imported solids or co-digestion feedstock receiving. In addition, these are relatively small projects that are subject to fairly high costs per kilowatt of installed capacity.

Electrical savings: The projects that were approved by their utilities benefited from higher savings rates per kilowatt-hour.

Electrical cost escalation: CHP systems can be used as a hedge against increasing electrical costs. Only two of the feasibility studies appeared to consider the impact of increasing electrical rates on project feasibility.

O&M costs: Table 5-3 shows a range of estimates for O&M costs per kilowatt-hour, with higher estimated costs per kilowatt-hour for smaller or underutilized systems. It is worth noting that WRRF 10 had one of the higher estimated O&M values based on a firm five-year contract for O&M services. This may suggest that the other estimated O&M costs are somewhat optimistic. On the other hand, all of the estimates exceeded the values presented in a recent report by the EPA CHP Partnership (EPA, 2011), which cites estimated maintenance cost as $0.02/kWh for small engines and $0.016/kWh for larger engine systems. Maintenance costs for WRRFs using CHP can vary considerably, with some facilities having maintenance costs as high as $0.07/kWh, primarily due to excessive contaminants in the digester gas leading to very high fuel treatment costs.

Availability: Similar to O&M costs, the CHP system availability estimates are fairly optimistic relative to the guaranteed values offered by a commercial entity. CHP system availability affects both the electrical consumption savings and demand charges because outages can trigger higher demand charges during the affected months.

“Go” criterion: Three of the projects that were not approved by their wastewater utility cited a “go” criterion of a 12- to 15-year payback, which is a somewhat higher bar than the break-even criterion cited in Section 5.2.1.

Considering these observations, overall, overly conservative financial feasibility assumptions have not been a significant factor in preventing financially attractive biogas projects from moving forward. Instead, the projects that do not move ahead appear to struggle with the adverse economic effects of small-scale, low local electrical rates, and ancillary digestion project capital costs.
Table 5-3. Comparison of CHP Financial Viability Parameters and Assumptions.

<table>
<thead>
<tr>
<th>Utility and WRFF</th>
<th>Generator Size (kW)</th>
<th>Capital Cost ($/kW)</th>
<th>O&amp;M Cost ($/kWh)</th>
<th>Electrical Savings ($/kWh)</th>
<th>Electrical Escalation Assumption</th>
<th>Assumed Availability</th>
<th>Grant Funding and Financing Assumptions</th>
<th>Financial Metric Assigned</th>
<th>“Go” Criteria</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Projects Approved by Wastewater Utility</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WRRF 1</td>
<td>520</td>
<td>6,000</td>
<td>0.0352</td>
<td>0.10</td>
<td>None</td>
<td>97%</td>
<td>8% of total project</td>
<td>$367,500/year savings for CHP</td>
<td>More cost-effective than other solids alternatives</td>
</tr>
<tr>
<td>WRRF 21</td>
<td>700 biogas</td>
<td>2,700</td>
<td>0.017</td>
<td>92,000/year demand response</td>
<td>None</td>
<td>Not shown</td>
<td>NY Microgrid Challenge</td>
<td>5–7 years</td>
<td>None identified</td>
</tr>
<tr>
<td>WRRF 10</td>
<td>(4) @ 65 kW</td>
<td>Not provided</td>
<td>(0.02)</td>
<td>0.11</td>
<td>3.5%</td>
<td>85%</td>
<td>Partial ARRA funding</td>
<td>$142,000 first-year project energy benefit</td>
<td>ESCO performance guarantee for several energy projects</td>
</tr>
<tr>
<td>WRRF 20</td>
<td>125–200</td>
<td>4,500–3,500</td>
<td>0.03</td>
<td>0.16</td>
<td>None</td>
<td>95%</td>
<td>No grant assumed; 6% interest</td>
<td>$66,000 positive cash flow</td>
<td>Positive first-year cash flow</td>
</tr>
<tr>
<td><strong>Projects Not Approved by Wastewater Utility</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>WRRF 16: Steam Turbine</td>
<td>475</td>
<td>10,000</td>
<td>None included</td>
<td>0.0657 (first year)</td>
<td>2.5%</td>
<td>None</td>
<td>15%</td>
<td>4% ROI</td>
<td>None identified</td>
</tr>
<tr>
<td>WRRF 14</td>
<td>130</td>
<td>10,100</td>
<td>0.05</td>
<td>0.078</td>
<td>None</td>
<td>96%</td>
<td>None assumed</td>
<td>51-year simple payback</td>
<td>12–15 years</td>
</tr>
<tr>
<td>WRRF 14</td>
<td>130</td>
<td>16,500</td>
<td>0.03</td>
<td>0.080</td>
<td>None</td>
<td>96%</td>
<td>None assumed</td>
<td>29-year simple payback</td>
<td>12–15 years</td>
</tr>
<tr>
<td>WRRF 12</td>
<td>600</td>
<td>10,200</td>
<td>0.02</td>
<td>0.077</td>
<td>None</td>
<td>98%</td>
<td>None assumed</td>
<td>19-years</td>
<td>12–15 years</td>
</tr>
</tbody>
</table>
a. Savings are accrued differently because WRRF 17 includes water, wastewater, and power. Savings are derived from the ability to monetize demand response services and to minimize penalties associated with reductions in penalties from exceeding monthly demand allocations during winter months.
b. Includes parasitic loads.
c. ECM-6a for two 65 kW microturbines assuming biogas production of 15 ft³ per lb VSD.
d. ECM 6+6a for imported raw solids receiving and two 65 kW microturbines assuming biogas production of 15 cf³ per lb VSD.
e. Recommended alternative ECM-22i for three 200 kW microturbines, assumed increase in biogas production for digester mixing improvements, and gas storage membrane.
f. Feasibility report states that this is the “rate charged the Sewer Fund by the General Fund.”
g. Electric (bills show $0.085/kWh average including kW and kWh charges) and $0.6/therm.
h. Does not include potential increase in natural gas expenditures.
i. Winter 90%, summer 75% per ESCO measurement and verification agreement. ESCO performance guarantee is for uptime only, not energy cost savings
j. Assumed reduction in O&M relative to previous cogeneration system. Maintenance agreement for first 5 years of microturbine and gas treatment skid service is $0.044/kWh.
5.3 Non-Monetary Benefit Evaluations

Section 5.2 previously discussed the range of non-monetary benefits that can be realized by biogas CHP systems. The AD and biogas feasibility reports evaluated in the previous section were also reviewed to determine to what extent they included estimates of non-monetary electrical grid and environmental benefits. As noted in Table 5-4, many of the reviewed feasibility evaluations failed to capture several of these benefits. Similar to the financial evaluations, the estimates of non-monetary benefits compiled by the reviewers did not follow a standardized approach.

Table 5-4. Non-Monetary Benefit Analysis Approaches Included in Feasibility Analyses.

<table>
<thead>
<tr>
<th>Utility and WRRF</th>
<th>Avoided Peak Demand</th>
<th>Avoided Distribution Losses</th>
<th>Monetized NOx and SOx Emissions Credits</th>
<th>Estimated GHG Emissions Credits</th>
<th>Marginal Emissions Rate Basis</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>WRRF 16</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>✓</td>
<td>✓ a, d</td>
<td></td>
</tr>
<tr>
<td>WRRF 21</td>
<td>✓</td>
<td>-</td>
<td>✓</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>WRRF 1</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>WRRFs 12 and 14</td>
<td>-</td>
<td>-</td>
<td>✓ b</td>
<td>✓</td>
<td>✓ c, d</td>
<td></td>
</tr>
<tr>
<td>WRRF 20</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

a. 1,540 lb/MWh.
b. Quantities SO2 estimated but not monetized. NOx emissions reductions not included.
c. 830 lb/MWh.
d. For reference, NYS average CO2e emissions rate is 564 lb/MWh. For the fuel mix in upstate NYS the eGRID fossil fuel emissions rate is 1,085 lb/MWh.

5.4 Organizational Barriers

Despite acceptable economic feasibility and/or compelling state-of-good-repair justifications, a couple of projects seemed to be hung up at the city hall (or county) level, highlighting the obstacles that can be encountered as projects move through various governmental entities for authorization.

In addition to resistance from city management, a few WRRF staff expressed reluctance to take on the additional O&M effort required by CHP systems.

5.5 Wastewater Utility Perception of Alternative Project Delivery Methods

A previous NYSERDA report titled “Anaerobic Digester Business Model and Financing Options for Dairy Farms” (Hoyt, 2014) describes alternative project delivery methods for biogas projects, including third-party ownership, partnership with an industrial substrate provider, and cluster financing to aggregate smaller projects under an investment and management partnership. Although dairy farm systems are often smaller than those at WRRFs, this report provides a useful investigation of alternative financing structures to move AD and biogas projects forward. Similar to observations made previously in this chapter, key challenges noted by the Hoyt report were low electrical rates and midlife costs such as major engine overhaul.
5.5.1 ESCO Project Delivery

Reactions to alternative project delivery methods by interviewed WRRF staff differed. The facilities identified as WRRF 3, WRRF 10, and the municipality that operates WRRFs 12 through 14, have pursued or are pursuing significant energy projects using the ESCO delivery method. Utilities that were not interested in ESCOs wanted more local control of the project and did not want to pay the ESCO’s markup.

5.5.2 Power Purchase Agreements

Public-private partnership firms have approached several of the interviewed utilities. At least one utility is seriously considering third-party developer approaches. The use of PPAs with third-party ownership of an AD system can be an effective way to transfer a portion of the risks away from the wastewater utility. Reservations expressed by WRRF staff regarding third-party developers and PPA delivery methods included the following:

- Some utilities seemed wary over the long commitment period associated with third-party arrangements.
- Some utilities cited conflicts with their existing electrical purchase contracts, or lack of financial motivation due to very low contracted electrical rates.

WRRF 10 implemented a biogas project using ESCO delivery, but not ESCO financing. The benefits of this delivery method included performance guarantees and third-party responsibility for O&M.
CHAPTER 6.0

CONCLUSIONS

The investigations in this study provide insight regarding the conditions that challenge the economic feasibility of biogas projects. Local and national initiatives are needed to continue the growth in beneficial biogas utilization. In addition, better, more thoughtful, approaches to presenting biogas feasibility and risk mitigation are needed to improve communications with decision makers so that good projects can move forward based on credible documentation of their merits.

6.1 Current Industry Perceptions and Practices for Advancing AD Projects

This section summarizes our findings relative to the original objectives of the study.

♦ What makes AD projects attractive?
  • **Minimizing waste**: Biogas utilization projects are widely recognized as an opportunity to minimize biogas flaring and use a “wasted” resource.
  • **Rate neutrality**: Projects that at least break even on a life-cycle basis so that they do not put upward pressure on rates.
  • **Vertical organizational support**: In successful AD and biogas projects, advocates fostered community and staff buy-in to build support across organizational levels.

♦ What drives the economics of AD projects?
  • **Contracted power rates**: Deregulated power markets have created opportunities for some municipalities to purchase generation and delivery services at very competitive rates, which benefits WRRFs by reducing operating costs but reduces their ability to cost-justify biogas CHP projects.
  • **Billing breakdown between fixed, demand, and consumption costs**: CHP systems have periodic planned maintenance and unplanned outages that affect monthly peak demand. Several utilities have contracted rate structures that include high fixed and demand charges, and ratcheted minimum demand charges that can erode CHP savings. Demand charges varied from 8% to 77% of total WRRF electrical expenditures among the WRRF sites reviewed for this study. These separate charges should be analyzed discretely to accurately estimate future savings.
  • **Project scale**: Small biogas CHP projects are at an economic disadvantage because of higher capital costs per kilowatt of installed capacity. Smaller-scale technologies such as microturbines can help to mitigate this disadvantage.

♦ Are sufficient BCA tools available and used by wastewater utilities?
  • **Lack of standardized approach**: The feasibility studies reviewed for this report varied widely in approach and level of detail, in terms of both financial evaluations and quantification of non-monetary benefits.
  • **Under-reporting of non-monetary benefits**: Non-monetary benefits, including GHG, NOₓ, and SOₓ emission reductions through reduced fossil fuel electrical generation, reduced GHG emissions from landfills of organic wastes, low-cost waste treatment for local wet industries, lower peak demand, avoided distribution losses, and associated
generation infrastructure needs, were often not estimated, not correctly estimated, or not considered in decision making.

- **NYSERDA microgrid BCA:** This tool captures most of the factors that are relevant to AD projects. Customizing this tool for AD projects would standardize and improve the quality of economic and non-monetary analysis. Additionally, some wastewater facilities may wish to consider using a broader microgrid approach to maximize the resiliency benefits of CHP projects by considering integration with other renewable and standby power sources.

- Which risk factors are prominent and what are potential means to overcome those risks?
  - **Economic factors:** Within the projects reviewed for the study that did not move forward, most were stalled by lack of economic feasibility.
  - **Biogas quantity:** Some plants expressed concern about whether they would have enough biogas to ensure project viability, because of either low plant flows or uncertainty in organic feedstock procurement.
  - **Staffing:** Some plants expressed concerns about whether O&M requirements would undermine financial viability, divert staff from other functions, or cause issues within their unionized workforce.

- Can environmental benefits be monetized through incentives?
  - **Clean Energy Standard:** Under the CES, the REC market will continue to provide some support for renewable power generators, including biogas CHP projects. However, as production costs have dropped for wind and solar generation, the financial benefit to wastewater utilities has become relatively small.
  - **Base load benefits:** Unlike solar and wind power, well-operated biogas generation systems have high (typically 90-95%) availability and minimal output variation. Future REC procurement or other green power purchasing programs could be structured to monetize this beneficial attribute.
  - **Other grid benefits:** No mechanism currently exists for monetizing other environmental benefits from distributed power generation, including the emission reductions associated with reduced grid losses.

- Based on current conditions, what are the best financing/funding approaches for municipal wastewater utilities pursuing biogas utilization projects?
  - **Capital cost support:** Utilities expressed interest in funding approaches that reduced their capital cost contribution in order to reduce their exposure to financing costs that could impact rates if savings fall short of expectations.
  - **Alternative delivery:** Some utilities appear to be successfully using ESCO delivery methods. ESCO performance guarantees are used to mitigate financial risk for biogas projects. ESCO and third-party financing is available as an alternative to bonding or state financing for energy projects, but does not appear to be widely used.

### 6.2 Recommendations to Make More Projects Viable

The final objective of this study posed the question, “Are there regulatory or other barriers that might be changed or other features that NYS government could employ to further reduce hurdles to wastewater biogas projects?” As noted above, the investigations presented point to several potential opportunities for facilitating credible decision-making processes that advance financially viable biogas projects. The following recommendations summarize approaches that state and federal entities could take to further reduce hurdles:
Level playing field for subsidizing biogas projects: Various state and federal policies have provided tax credits and other incentives intended to advance wind, solar, and other energy types, but biogas projects have not had consistent support. When tax credits are available, only privately developed projects are eligible. WRRFs need new approaches to bridge the economic gap for communities where moderate electrical rates limit the financial feasibility of biogas CHP projects.

Maximize REC benefits: Proposed California legislation that would allow RECs to be awarded for electrical power generated from biogas and consumed behind the meter could be used by NYS as a model to adapt state REC policies to the needs of wastewater utilities.

Collaborative electrical procurement: WRRFs are attractive loads for electrical utilities because they are large and relatively stable, but municipal procurement of electrical services can be complex and negotiated contract terms may not be well tailored to wastewater utility needs. Individual municipal entities may benefit from a coordinated approach to finding electrical contracting provisions that maximize savings from onsite energy generation for these large energy-consuming facilities and improve cost certainty for monthly electrical expenses. As an example, the NYS Office of General Services (OGS) provides centralized energy planning and procurement for the state’s building portfolio.

Regional approaches: Supporting regional approaches to AD can improve economies of scale for projects, often with surprisingly small GHG impacts related to transporting solids relative to the potential GHG benefits from biogas projects. For example, the municipality that operates WRRFs 12 and 14 currently hauls solids between WRRFs. It is considering capital project alternatives that would optimize existing AD capacity utilization and maximize benefits from future biogas utilization. Another utility suggested that a pipeline could be cost-effectively implemented to transfer solids between WRRFs, but this approach faces jurisdictional hurdles because the plants are owned by different utilities.

Biogas fuel end uses: The biogas market is rapidly evolving and vehicle fuel/pipeline projects are becoming more common as the technology to produce pipeline-quality gas has become widely available. As such, NYSERDA programming may need to allow flexibility to determine the best fit for each site. This is especially true in cases where electrical rates are very low and vehicle fuel alternatives may improve economic feasibility.

Future biogas technologies: A collaboration between the Bioenergy Technology office of DOE, EPA, and the National Science Foundation (NSF) has been conducting a series of workshops exploring the water-energy-food nexus, including future technology pathways to make resource recovery more economically viable. This collaboration is looking beyond current paradigms for biogas utilization toward new technologies that would create drop-in liquid transportation fuels or other high-value products from biogas feedstocks. NYS has some leading researchers in this area and should continue to monitor and support future alternatives that may increase biogas resource recovery benefits.
6.3 Risk Mitigation Approaches

Biogas energy projects are often perceived as risky, in part because they conflict with the standard definition of a WRRF’s core mission. A conflict often emerges between operations’ and engineering/executives’ vision of the primary mission of a WRRF. This disconnect can lead to projects being delayed or canceled through overly conservative assumptions or criteria set by stakeholders who do not share the same vision. Risk mitigation is required to increase buy-in at all organizational levels:

6.3.1 Project Cost Containment

Biogas project economic feasibility often requires tight control of capital costs, but several factors work against this objective:

- **Aging digestion facilities**: Many WRRFs with digestion are very old and need upgrades to make them viable for co-digestion. Without good digester operations, AD and co-digestion projects can falter. Co-digestion and biogas projects must be viewed in conjunction with state-of-good-repair capital investments.

- **Project cost creep**: As with many types of capital projects, biogas projects are subject to increasing costs during project design because project details such as electrical tie-ins, biogas quality, and site modifications are not adequately considered during the initial project feasibility study. Because biogas projects are somewhat discretionary, a two-phase approach could allow assessment of preliminary feasibility, followed by a detailed feasibility investigation. These two levels of analysis would provide a second “off-ramp” opportunity if adverse conditions are discovered – prior to the utility’s final commitment to a detailed design and construction project.

Many facilities take the “whole enchilada” approach and build everything up front to get an economy of scale rather than taking a modular design approach with an incremental expansion plan. However, effective strategic planning of facilities implementation can allow a phase-in of facilities over time. For example, the well-known East Bay Municipal Utility District (EBMUD) fats, oils, and grease (FOG) station was a portable tank and pumps for a long time before a permanent system was installed.

6.3.2 Controlling Long-Term Operating Costs and Electrical Savings

Following project commissioning, plant staff must carefully manage costs and monitor electrical savings. Upfront planning can help WRRFs tackle these new challenges:

- **Staffing**: Often WRRF staff are stretched thin and the added workload of AD and biogas programs is viewed negatively. Consideration of staffing and contracted O&M support during the planning period can alleviate this concern.

- **Energy cost fluctuations impacting savings**: NYS WRRFs appear to often have the benefit of long-term electrical contract arrangements. It is important to leverage these business relationships to make sure that energy cost trends are well understood during the planning phase.

- **Equipment failures or excessive O&M**: Biogas CHP systems are complex and subject to major failures and long-term outages if they are not continuously maintained. Commitment to ongoing proactive maintenance and specialized staff training is essential to avoid these failures.
6.3.3 Co-Digestion Risks

Because co-digestion programs bring new relationships with feedstock suppliers, co-digestion projects have unique risks that need to be considered:

- **Procurement of feedstock:** It is often difficult to procure feedstock in advance of a program, especially if private businesses need to make additional investments. In addition, the view of what constitutes a long-term contract can differ between the private and public sectors. Many waste haulers see five years or less as long term, which differs from the 20-year contracts municipalities are used to. Redundant future feedstock sources may be required to provide flexibility for changing scenarios.

- **Feedstock compatibility:** Coordination between generators of high-strength organic waste and WRRFs is required to ensure that proper material is delivered to the facility. With proper process controls, source tracking, monitoring, and waste characterization, the likelihood of significant inhibition is relatively low. New waste streams can be screened based on chemical criteria such as pH and salinity, as well as testing for standard pollutants and heavy metals. Other compatibility issues include:
  - Organics recovered from processed solid waste might not be wet enough for WRRF digestion.
  - Some feedstocks may contain inhibitory or toxic levels of biocides and similar cleaning products.
  - Feedstocks may contain high nitrogen, resulting in increased ammonia levels in the digesters, which can be inhibitory.
  - Fats are excellent feedstocks, but their breakdown can result in high concentrations of long-chain fatty acids, which can be inhibitory at sufficiently high concentrations.

- **Tipping fees relative to landfill disposal:** The price difference between putting organic waste in a landfill and pre-processing and digestion needs to be sufficient to create a business driver for diversion, especially in the non-regulated private sector (assuming no diversion laws are in place to impose this driver). Low landfill tip fees can make it financially non-viable for suppliers to divert materials.
REFERENCES


