Appendix D: Background Documents Provided to Reviewers

- **2015 LFGcost Peer Review White Paper (dated 10.6.2015)**
- **Documentation of Updated and New Costs Incorporated into LFGcost-Web, Version 3.0 (dated 06.16.2014)**
- **DRAFT Updated Methodology for Estimating Cost and Emission Impacts of MSW Landfill Regulations (dated June 2015)**

EPA's Landfill Methane Outreach Program
Overview of Landfill Gas Energy Cost Model
LFGcost-Web, Version 3.0, August 2014

Background: Landfill Gas Collection, Control, and Energy Recovery

Landfill gas (LFG) is emitted from decomposing organic material in municipal solid waste (MSW) landfills. LFG contains roughly 50 to 55 percent methane and 45 to 50 percent carbon dioxide, with less than one percent non-methane organic compounds (NMOCs) and trace amounts of inorganic compounds. Approximately 254 million tons of MSW were generated in the United States in 2013, with nearly 53 percent of that deposited in landfills.[1] LFG generation rates are typically estimated using a first-order decay equation. In general, a landfill's LFG generation rate increases until the landfill stops accepting waste. After closure, the LFG generation rate declines over time. The types of incoming waste, site operating conditions, and moisture and temperature conditions may cause substantial variations in the actual rate of generation. Figure 1 shows an example of LFG generation in two different operating conditions for a landfill that closed in 2012.

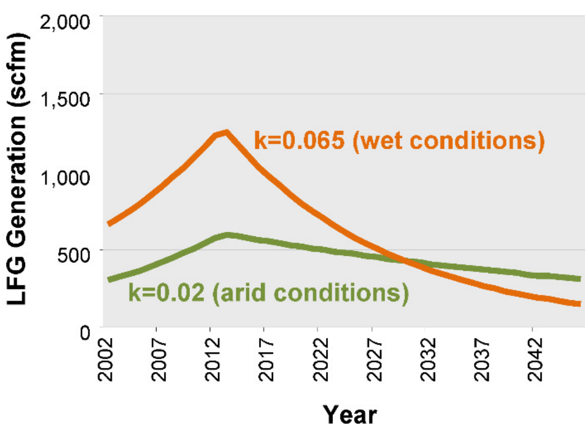

Figure 1. Example LFG Generation Curves

Landfills collect and control LFG with a gas collection and control system (GCCS) either because they are required under local, state, or federal regulations or opt to take voluntary action. Further, when cost-effective, many landfills use LFG through the voluntary development of an LFG energy project. LFG can be used to produce a reliable, local, and renewable source of energy that can provide a variety of environmental and economic benefits. LFG energy can be

[1] Of the MSW generated in 2013, more than 34 percent was recovered through recycling or composting while about 13 percent was combusted with energy recovery. Source: U.S. EPA. 2013. Advancing Sustainable Materials Management: 2013 Fact Sheet; see: http://www.epa.gov/wastes/nonhaz/municipal/pubs/2013_advncng_smm_fs.pdf.

used to generate electricity, provide direct thermal energy, or support other applications (such as vehicle fuel).

Collected LFG is typically combusted in flares or combustion devices that recover energy, such as boilers, internal combustion engines, and gas turbines.[2] Properly designed and operated combustion equipment generally reduces NMOC emissions by 98 percent or to a 20 ppmv outlet concentration, as specified in the current MSW landfills EG (40 CFR 60.752). Combustion also destroys over 98 percent of the methane. Flares are the most common control device used at landfills. The Landfill Methane Outreach Program's (LMOP) Landfill and Landfill Gas Energy Project Database (LMOP Database) reports that 513 landfills (or approximately 21% of existing landfills) flare LFG with no energy recovery component.[3]

A GCCS consists of a wellfield, a pipe gathering system to transport the gas to a central location, a blower to actively extract the gas to a central location, and a flare system to combust the LFG. When an energy project is employed, the flare system serves as a back-up destruction device when the energy project is not operating or as a mechanism for handling excess collected LFG. Figure 2 presents an overview of LFG collection, treatment, and energy recovery components.

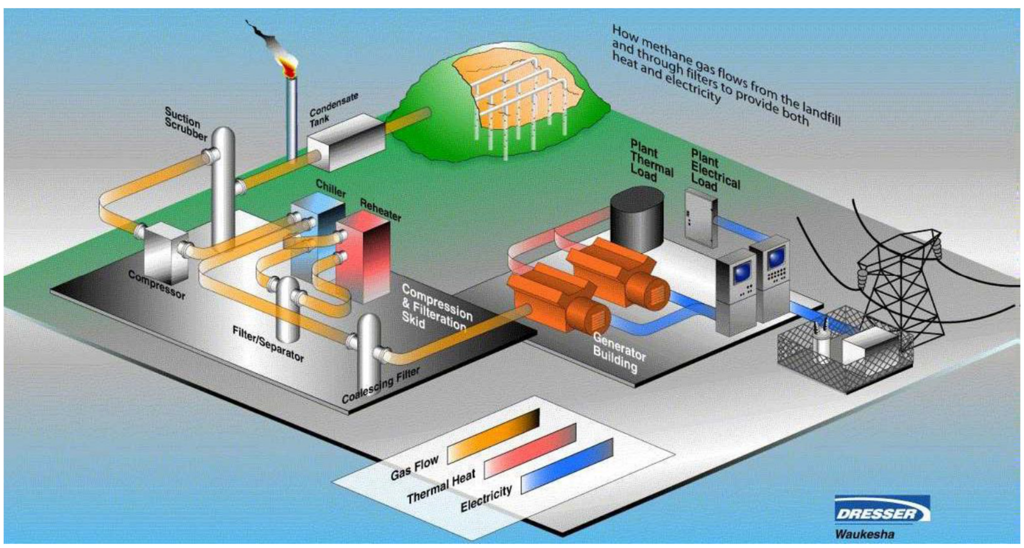

Figure 2. Overview of LFG Collection, Treatment, and Energy Recovery
Graphic courtesy of Dresser Waukesha

[2] Flares are a component of each energy recovery option because they may be needed to control LFG emissions during energy recovery system startup and downtime and to control any gas that exceeds the capacity of the energy conversion equipment.

[3] The LMOP Database is not purported to contain data for every MSW landfill in the United States, but is believed to contain the majority of the MSW landfills that are accepting waste or have accepted waste during the past 30 years. Information in the LMOP Database is compiled from a variety of sources by voluntary submittal, is updated periodically, and can change.

Introduction to Estimating Costs for LFG Collection, Control, and Energy Recovery

LFG Collection and Control

The costs of LFG collection and control can vary depending on several design variables of the GCCS (also referred to as the collection and flaring system). For example, if a landfill is deep, collection costs tend to be higher because the well depths will need to be increased. Collection costs also increase with the number of wells installed. The components and key factors that influence the costs of the GCCS are presented below, in Table 1.

Table 1. Gas Collection and Control System Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Gas Collection and Control Systems (GCCS) (Also referred to as Collection and Flaring Systems)	
Gas collection wells or connectors	• Area and depth of waste • Spacing of wells or connectors
Gas piping	• LFG flow rate • Length of piping required
Condensation knockout drum	• Volume of drum required
Blower	• Size of blower required (a function of LFG flow rate)
Flare	• Type of flare (open, ground, or elevated) • Size of flare (a function of LFG flow rate)
Instrumentation and control system	• Types of controls required

Energy Recovery and Utilization

A variety of factors influence whether a landfill pursues energy recovery or not, and if so, what type of energy project is most suitable. The primary factor in choosing the right project configuration for a particular landfill is the projected expense versus the potential revenue. This equation, in turn, is affected by a number of factors such as the size of the project, end use application (e.g., electricity generation), energy prices, proximity of the end user to the landfill, relevant green energy incentives, and the size of the project. State and local air quality regulations can also play a role in technology selection.

In the United States, according to the LMOP Database, there are 645 LFG energy projects in operation as of March 2015.[4] The most common type of LFG energy recovery project is electricity generation; roughly three-fourths of projects generate electricity. The most typical technology options available for developing an electricity project are internal combustion

[4] The LMOP Database, which tracks the development of U.S. LFG energy projects and landfills with project development potential, indicates that 645 LFG energy projects are currently operating in the United States (March 2015). See www.epa.gov/lmop for more information.

engines. In general, costs for these types of projects include electricity generation equipment and typical compression and treatment systems appropriate to the particular technology and interconnection equipment. System components and key factors that influence the costs of an electricity project are presented below, in Table 2.

Table 2. Electricity Generation System Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Electricity Generation Systems/Standard Engine Generators	
Engine size	• Flow rate (gas curve) • Electricity rate structures • Minimum electricity generation requirements (contract obligations)
Capacity to expand	• Maximum flow rate • LFG flow rate over time (gas curve)
Gas compression and treatment equipment	• Quality of the LFG (methane content) • Contaminants (e.g., siloxane, hydrogen sulfide)
Interconnection equipment	• Project size • Local utility requirements and policies

Other than electricity generation, direct-use projects in the United States are also common, representing approximately 20 percent of existing energy recovery projects. A direct-use project may be a viable option if an end user is located within a reasonable distance of the landfill. Boilers are the most common type of direct use, and LFG is used in boilers at a wide variety of industrial manufacturing facilities as well as commercial and institutional buildings. Other examples of direct-use projects include process heaters, kilns or furnaces; or space heating for commercial, industrial, or institutional facilities or for greenhouses. In general, costs for the gas compression and treatment system include compression, moisture removal, and filtration equipment typically required to prepare the gas for transport through the pipeline and for use in a boiler or process heater. It is important to note that costs for direct-use projects vary depending on the end user's requirements and the size of the pipelines (where applicable). Direct-use system components and key factors that influence the costs of a project are presented below, in Table 3.

Table 3. Direct-Use Project Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Direct-Use Systems/Direct Thermal	
End use of the LFG	• Type of equipment (e.g., boiler, process heater, kiln furnace) • LFG flow rate over time • Requirements to modify existing equipment to use LFG

Component / Attribute	Key Site-Specific Factors
Gas compression and treatment equipment	• Quality of the LFG (methane content) • Contaminants and moisture removal requirements • Filtration requirements
Gas pipeline	• Length (distance to the end use) • Obstacles along the pipeline route • LFG flow rate
Condensate management system	• Length of the gas pipeline

Aside from electricity generation (which includes cogeneration[5]) and direct-use project types, LFG energy can be converted into renewable compressed natural gas or liquefied natural gas or converted into a higher quality gas and injected into pipelines. These niche project types represent just over 5 percent of existing LFG energy projects.

Estimating Costs for LFG Collection, Control and Energy Recovery: The LFGcost-Web Model

Since the production of energy from LFG is a revenue driven activity, landfill owners and developers first have to evaluate the economic feasibility of an energy project to prepare a system design, enter into contracts, or purchase materials or equipment. To help stakeholders estimate the costs of an LFG energy project, in 2002, LMOP developed a cost tool (LFGcost). Since then, LMOP has routinely updated the tool to reflect changes in the LFG energy industry. Initially this model was designed for internal EPA and contractor use. In 2014, LMOP developed a public version of the model, LFGcost-Web (V3.0), which was made available to the general public when it was posted on a public page of the LMOP website later that year. LFGcost-Web can analyze costs for 12 energy recovery project types. These project costs can be estimated with or without the costs of a GCCS.[6] LFGcost-Web was designed to serve as a rough order of magnitude costing tool, is used by industry as preliminary cost-analysis tool, and has an estimated accuracy of ±30-50 percent.

The default inputs and costs estimated by LFGcost-Web are based on typical project designs and for typical landfill situations. The model attempts to include all equipment, site work,

[5] Cogeneration, also known as combined heat and power (CHP), projects use LFG to generate both electricity and thermal energy, usually in the form of steam or hot water. The efficiency gains of capturing the thermal energy in addition to electricity generation can make these projects very attractive.

[6] The various LFG energy project types that can be analyzed in LFGcost-Web include: direct LFG utilization projects (direct-use); boiler retrofit projects; processing LFG into a high Btu gas; processing LFG into an alternative vehicle fuel (CNG); leachate evaporators; electricity generation with standard turbines; electricity generation with standard reciprocating engines; electricity generation with microturbines; electricity generation with small reciprocating engines; electricity generation and hot water production with combined heat and power (CHP) reciprocating engines; electricity generation and steam production with CHP turbines; and electricity generation and hot water production with CHP microturbines. Costs for each of these project types can be estimated with or without the cost of installing a new GCCS.

permits, operating activities, and maintenance that would normally be required for constructing and operating a typical project. However, individual landfills may require unique design modifications which would add to the cost estimated by LFGcost-Web.

LFGcost-Web estimates costs for gas collection, flaring, and energy recovery systems and was developed based on cost data from actual installations obtained from equipment vendors and consulting engineering firms that have installed and operated numerous GCCS and energy projects. LFGcost-Web includes three types of costs for installing and operating LFG systems: installed capital costs, annual operating and maintenance (O&M) costs (energy costs and non-energy costs), and revenue from LFG energy sales or other market mechanisms. More specifically:

- **Total capital costs** include purchased equipment costs, installation costs (including mobilization of construction equipment), engineering and design costs, costs for site preparation and buildings, and costs of permits and fees.
- **Annual O&M costs** include labor and non-labor (e.g., energy to operate system, parts and materials, taxes, administration, financing) costs.
- **Revenue** can include sales of LFG electricity or other LFG products such as pipeline quality gas or vehicle fuel, renewable energy credits, or carbon credits.

Appendix A of this memorandum includes an excerpt of detailed equations and system components included in the LFGcost-Web model for the following three modules: (1) Collection and Flaring System (C&F), (2) Standard Reciprocating Engine-Generator Set (ENG), and (3) Direct-Use System (DIR) modules. As stated previously, LFGcost-Web can analyze costs for 12 energy project types with or without a GCCS. The user selects the project type of interest, and whether to include a GCCS, at the outset. For purposes of this document, only two energy modules and the GCCS module were included in Appendix A. Those three modules were selected because a GCCS is required for landfills required by regulation to collect and combust LFG. Additionally, GCCS infrastructure is necessary to operate all types of energy projects, and the LFG energy project types included in Appendix A represent the most common ones used for electricity generation (via a standard reciprocating engine) and direct use (e.g., in an industrial boiler). Appendix A also includes a list and basis of select default parameters used to estimate costs in the model.

How was LFGcost-Web Model Used in the Proposed MSW Landfill Rules?

To estimate costs of the regulatory options in the 2015 proposed revisions to the MSW Landfills Standards of Performance (also known as New Source Performance Standards) and the Emission Guidelines[7] (herein thereafter referred to collectively as the Landfill Rules), the EPA

[7] In 2014, the EPA proposed revisions to the "Standards of Performance for Municipal Solid Waste Landfills" (79 FR 41796, July 17, 2014) and issued an Advanced Notice of Proposed Rulemaking for the "Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills" (79 FR 41772, July 17, 2014). Subsequently, in 2015, the EPA issued a supplementary proposal to the "Standards of Performance for Municipal Solid Waste Landfills" (80 FR 52162, August 27, 2015) and proposed revisions to the "Emission Guidelines and Compliance Times for Municipal

utilized equations from LFGcost-Web. More specifically, equations derived from LFGcost-Web were applied to each landfill expected to be impacted by the Landfill Rules to estimate annualized installed capital costs and annual O&M costs of a GCCS. The list of landfills expected to be impacted by the Landfill Rules in year 2025 was based on the reported design capacity of the landfill, an estimated LFG generation rate and NMOC emission rate for each landfill, and an estimated length of time needed to install a GCCS after the specified NMOC emission threshold was reached (initial lag time).

After applying the LFGcost-Web equations to the list of landfills expected to require a GCCS in year 2025 as a result of the proposed Landfill Rules, the regulatory analysis evaluated whether electricity generation (using a standard reciprocating engine) would be profitable. Engines were assumed to be installed only at landfills that produced enough LFG to power the engine and only when the electricity buyback rates allowed the operation of the engine to be profitable. Where profitable, annualized installed capital costs, annual O&M costs, and annual revenue from electricity sales were also derived using equations from LFGcost-Web for standard reciprocating engine-generator sets. The resulting equations were used to calculate estimated costs in the regulatory impacts analysis (RIA).[8] This is the first time EPA has used LFGcost in the development of regulations to control emissions of LFG under the Clean Air Act (40 CFR part 60). In the development of previous landfill regulations, EPA estimated costs based on feedback from industry and select stakeholders.[9]

Solid Waste Landfills" (80 FR 52100, August 27, 2015). As part of the 2015 actions, the EPA updated its model that estimates the emission reductions and cost impacts of changes to the design capacity thresholds and/or the NMOC emission rate trigger based on public comments and new data. The information in this document about the use of LFGcost-Web refers to the model's use in the 2015 supplemental proposal to the NSPS and the 2015 proposed revisions to the Emission Guidelines.

[8] See docketed RIA, August 2015 (EPA-HQ-OAR-2014-0451-0086) and docketed memorandum "Updated Methodology for Estimating Cost and Emission Impacts of MSW Landfill Regulations" (EPA-HQ-OAR-2014-0451-0077) by ERG, 2015.

[9] See "Changes to 1-29 the Municipal Solid Waste Landfills Nationwide Impacts Program Since Proposal" (Docket No. A-88-09, Item No. IV-M-3) or "Air Emissions from Municipal Solid Waste Landfills-Background Information for Proposed Standards and Guidelines", U.S. EPA (EPA-450/3-90-011a)(NTIS PB 91-197061) (available at http://www3.epa.gov/airtoxics/landfill/landflpg.html).

LFGcost-Web encompasses the types of costs included in the EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, including capital costs and annual costs:

- **Total capital costs** include purchased equipment costs, installation costs, engineering and design costs, costs for site preparation and buildings, costs of permits and fees, and working capital.
- **Total annual costs** include direct costs, indirect costs, and recovery credits.
    - **Direct annual costs** are those that are proportional to a facility-specific metric such as the facility's productive output or size.
    - **Indirect annual costs** are independent of facility-specific metrics and may include categories such as administrative charges, taxes, or insurance.
    - **Recovery credits** are for materials or energy recovered by the control system. For example, revenue generated from electricity sales.[10]

In the regulatory analysis for the Landfill Rules, all costs were presented in $2012. The costs included in LFGcost-Web are in $2013 and were adjusted to $2012 using a factor of 2 percent for capital costs and 2.5 percent for O&M costs (consistent with the model's default values, as shown in Appendix A). The regulatory analysis presented the annualized capital cost of all GCCS components (i.e., flares, wells, wellheads, blowers, and piping to collect gas), and engines over the lifetime of the equipment for each regulatory option under consideration. The regulatory analysis also included the annual costs to operate and maintain the equipment.

When conducting this analysis, EPA made several assumptions. First, EPA assumed that the equipment would be replaced when its lifetime was over if the landfill was still emitting above the proposed NMOC emission threshold. To estimate these costs, EPA assumed that the annualized capital costs were incurred as long as the landfill still had controls in place. To calculate the annualization factors, flares, wells, wellheads, and engines had a 15-year lifetime.

Second, since the Landfill Rules would require expansion of the GCCS over time, EPA assumed a mobilization/installation charge to bring well drilling equipment on site each time the GCCS was expanded. To comply, a landfill would drill wells to expand the control system during the year that the expansion would take place (also known as the expansion lag year). It was assumed that this capital installation cost had a lifetime equal to the expansion lag time.

Third, EPA made assumptions about the number of wells that would be installed at each landfill. In order to estimate the number of wells at each landfill, the number of acres that have been filled with waste for each landfill for each year were estimated. In addition, it was assumed that each landfill would install one well per acre, consistent with the guidelines provided in the LFGcost-Web model, and that the number of wells would increase periodically based on expansion lag time.

[10] The regulatory analysis did not consider potential revenue from carbon credits, renewable energy credits (RECs), or other tax credits.

Finally, EPA assumed engines would be installed only at landfills that produced enough LFG to power the engine and only when the electricity buyback rates allowed the operation of the engine to be profitable. Standard engines used at landfills have approximately 1 MW capacity, which equates to 195 million cubic feet (ft^3) per year of collected LFG (at 50 percent methane). Therefore, engines were assumed to be installed at landfills that had at least 195 million ft^3 per year of collected LFG for at least 15 years, which could be as late as 2039 for engines that were installed in 2025. The engine capital and O&M equations were calculated and summed to determine at what electricity buyback rate an engine would be profitable. The profitable electricity buyback rate was greater than $0.0594 per kilowatt-hour (kWh) at a 7 percent interest rate and greater than $0.0430 per kWh at a 3 percent interest rate; it was assumed engines were only installed in states with buyback rates exceeding those values.

Appendix A: Background LFGcost-Web (V3.0) Equations

C&F: Collection and Flaring System[a]	
Typical components include	• Engineering, permitting, and administration; • Wells and wellheads; • Pipe gathering system (includes additional fittings/installations); • Condensate knockout system; • Blowers; • Instrument controls; • Flare; and • Site survey, preparation, and utilities.
Drilling and pipe crew mobilization	\$20,000
Installed capital cost of vertical gas extraction wells	$\left(\begin{array}{c}\text{average waste} \\ \text{depth (ft)}\end{array} - 10\ \text{ft}\right) * \$85/\text{ft} = \$X/\text{well},$ (\$4,675 * number of wells) for default average waste depth of 65 feet
Installed capital cost of wellheads and pipe gathering system	\$17,000 * number of wells
Installed capital cost of knockout, blower, and flare system	$(\text{ft}^3/\text{min})^{0.61}$ * \$4,600
Engineering, permitting, and surveying	\$700 * number of wells
Annual O&M cost (excluding energy costs)	(\$2,600 * number of wells) + \$5,100 for flare
Electricity usage by blowers	0.002 kWh / ft^3

Source: LFGcost-Web (V3.0) User Manual.
[a] The LFGcost-Web module is called "C&F" and includes all components of a GCCS.
Note: Raw cost data are in \$2013s.

Appendix A: Background LFGcost-Web (V3.0) Equations

ENG: Standard Reciprocating Engine-Generator Set[a]	
Typical components include	▸ Gas compression and treatment (includes dehydration equipment and filtration); ▸ Reciprocating engine and generator (includes motor controls, switch-gear, radiators, exhaust silencers, and all wiring and plumbing); ▸ Electrical interconnect equipment; and ▸ Site work, housings, utilities, and total facility engineering, design, and permitting. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	[($1,300 * kW capacity) + $1,100,000] + $250,000 for interconnect
Annual O&M cost (excluding energy)	$0.025 * kWh generated/yr (before parasitic uses)
Parasitic loss efficiency	93% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	11,250 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%

Source: LFGcost-Web (V3.0) User Manual.

[a] This is one of 12 types of energy recovery projects in LFGcost-Web and the only energy recovery project type considered in the 2015 proposed Landfill Rules regulatory analysis.

Note: Raw cost data are in $2013s.

*Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities, and shut-downs at the energy consumer end of the system.

DIR: Direct-Use System[a]	
Typical components include	▸ Engineering, permitting, and administration; ▸ Skid-mounted filter, compressor, and dehydration unit; ▸ Pipeline to convey gas to project (includes below-grade HDPE piping, condensate removal system, and pipe fittings); and ▸ Site survey, preparation, and utilities. (Cost does not include payments for right-of-way easements which may or may not be required.)
Installed capital cost of skid-mounted filter, compressor, and dehydration unit	($360 * ft^3/min) + $830,000
Installed capital cost of pipeline	*For flow rates ≤1,000 ft^3/min (8" piping):* ($80* feet of pipeline) + $178,000 *For flow rates 1,001 - 3,000 ft^3/min (12" piping):* ($106 * feet of pipeline) + $207,000
Annual O&M cost (excluding electricity)	$\$57{,}000 * \left(\frac{\mathrm{ft}^3/\mathrm{min}}{700}\right)^{0.2}$
Electricity usage	*For pipeline distances of 5 miles or less:* 0.002 kWh/ft^3 *For pipeline distances where* $\left(\frac{miles * (ft^3/\min)^2}{10^6}\right) > 120:$ 0.003 kWh/ft^3
Gross capacity factor*	Assume 90%

Source: LFGcost-Web (V3.0) User Manual.

[a] This is one of 12 types of energy recovery projects in LFGcost-Web. While this energy recovery project type was not considered in the 2015 proposed Landfill Rules regulatory analysis, it is included here as it represents the second most common type of energy recovery project.

Note: Raw cost data are in $2013s.

*Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities, and shut-downs at the energy consumer end of the system.

Appendix A: LFGcost-Web (V3.0) Default Value Documentation[a]

Default Parameter in LFGcost-Web (V3.0)	**Value**	**Basis**
General Inflation Rate	2.5%	The general inflation rate fluctuates with economic conditions and many unforeseen factors, making it very difficult to forecast. The default inflation rate is based on the 5-year average annual increase in the Consumer Price Index (CPI). The 5-year average annual CPI rate increase of 2.1% for 2008-2012 is rounded to 2.5% for the default rate.
Equipment Inflation Rate	2.0%	The *Chemical Engineering* (*CE*) Plant Cost Index was used to determine the default equipment inflation rate. The average annual cost increase for the 5 years of 2008-2012 has been 2.4%. This rate was rounded to 2% for the LFGcost-Web default equipment inflation rate.

Source: LFGcost-Web (V3.0) User Manual.

[a] The table includes the default parameters in LFGcost-Web that were used in the regulatory analysis for the 2015 proposed Landfill Rules. A detailed discussion of the assumptions made for interest rates and electricity prices is discussed in a separate memorandum.[11] The regulatory analysis did not escalate electricity prices in the regulatory model in order to be conservative. The state level prices already have significant variation and uncertainty in the prices and the pricing will depend on local grid to some extent.

[11] See docketed memorandum "Updated Methodology for Estimating Cost and Emission Impacts of MSW Landfill Regulations" (EPA-HQ-OAR-2014-0451-0077) by ERG, 2015.

MEMORANDUM

To: Kirsten Cappel, LMOP

From: Amy Alexander, ERG, and Steve Wittmann, Cornerstone Environmental Group, LLC

Date: June 16, 2014

Subject: Documentation of Updated and New Costs Incorporated into LFGcost-Web, Version 3.0

INTRODUCTION

The purpose of this memorandum is to document updated and new cost equations incorporated into the new LFGcost-Web model (Version 3.0). The existing cost equations being updated are currently used in both the internal and Web versions of LFGcost (Internal V2.3 and Web V2.2).

As explained in the sections following this introduction, costs have been updated or added for the following modules within the model:

- Collection and flaring systems (updated),
- Direct-use systems (updated),
- Standard engine-generator sets (updated), and
- Onsite compressed natural gas (CNG) production and fueling station (added).

All new and updated cost data were provided by Cornerstone Environmental Group, LLC (Cornerstone) and are based on actual equipment installations in recent years (2010-2013). The new and updated cost equations are represented in 2013$'s (escalated from year of installation using the updated default equipment inflation rate of 2%), and serve as baseline costs for the modules listed above in the new model. These new cost data replace existing baseline costs in the model that are in 2008$'s.

Historically, cost estimates provided by the LFGcost model have been analyzed to result in a conservative estimate to avoid underestimating actual costs. Therefore, the updated and new cost equations presented below were determined following this same conservative methodology. Although this may result in an overestimate of costs, ERG recommends this approach for LFGcost as an initial feasibility assessment tool for LFG energy projects. In addition, cost data were often calculated to determine exact cost equations and then rounded up (to be conservative) to the nearest hundred or thousand to result in a more rounded value with the appropriate number of significant digits. This rounding procedure is documented in the cost equation tables below.

For methodologies provided in the cost equation tables below, the term "average" is used to represent the calculation of an arithmetic mean.

COLLECTION AND FLARING SYSTEMS

Cornerstone provided equipment cost data for seven collection and flaring systems installed in 2010-2013. Table 1 provides updated capital cost equations for collection and flaring systems (2013$'s) as well as the methodologies used to determine these typical costs.

Table 1. Collection & Flaring Installed Capital Cost Equations (Based on Installations in 2010-2013)

Collection and Flaring Equipment Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Drilling and Pipe Crew Mobilization	**$20,000 per system**	• Separate cost as it normally does not vary by landfill size or number of wells. • Calculated average for all installations ($18,330) and then rounded up to be conservative and account for exclusion of the maximum cost data point ($72,583) as a potential outlier.
Vertical Gas Extraction Wells	**$85 per linear foot of average waste depth**	• Calculated average $/linear foot of waste depth ($79/ft) and then rounded up to be conservative and reflect Cornerstone's suggested typical cost. • [(Average waste depth (ft) – 10 ft) * $85/ft] = $X/well, $4,675/well for default average waste depth of 65 ft.
Wellheads and Pipe Gathering System (including additional fittings/installations)	**$17,000 per well**	• Calculated average wellhead cost per well ($1,600/well) and then rounded up ($2,000/well) to be conservative. • Calculated average piping cost on a per well basis ($11,471/well) and then rounded up ($12,000/well) to be conservative and account for exclusion of the maximum cost data point ($32,282/well) as a potential outlier. • Calculated average cost per well for additional fittings and installations ($2,511/well) and then rounded up ($3,000/well) to be conservative. • Summed three rounded average costs ($2,000/well + $12,000/well + $3,000/well = $17,000/well).
Knockout, Blower, and Flare System[1]	**$(ft^3/min)^{0.61}$ * $4,600**	• Limited cost data for knockout, blower, and flare installations were provided for only two installations, which did not provide a sufficient number of data points to update costs. • Escalated cost equation for knockout, blower, and flare system in existing model from 2008$'s to 2013$'s [$(ft^3/min)^{0.61}$ * $4,527] and then rounded up to be conservative.
Engineering, Permitting, and Surveying	**$700 per well**	• Calculated average cost per well ($682/well) and then rounded up to be conservative.

[1] ft^3/min = collected LFG design flow rate
Escalated using updated default equipment inflation rate of 2%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.

Table 2 shows a comparison of collection and flaring capital costs for equations used in the existing model (both 2008$'s and escalated 2013$'s) and the new model.

Table 2. Comparison of Existing Model and New Model Capital Costs for Collection and Flaring Systems of Varying Sizes

# of Wells	Collected LFG Design Flow Rate (ft^3/min)[2]	Total Capital Costs for Collection and Flaring Systems		
		Existing Model – Baseline (2008$'s)	Existing Model – Escalated[3] (2013$'s)	New Model (2013$'s)
10	588	$411,544	$454,378	$468,751
15	882	$560,818	$619,189	$643,762
20	1,176	$703,082	$776,260	$810,909
25	1,471	$840,714	$928,216	$972,859
30	1,765	$974,971	$1,076,447	$1,131,022
35	2,059	$1,106,617	$1,221,795	$1,286,257
40	2,353	$1,236,161	$1,364,822	$1,439,132

[2] Calculated based on a gas collection system for 34 wells with a total LFG design capacity of 2,000 ft^3/min (equates to ~58.8 ft^3/min per well)

[3] Escalated using updated default equipment inflation rate of 2%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.

The model provides capital and annual operation and maintenance (O&M) costs in the same year's dollars. As O&M costs do not fluctuate significantly over time, annual O&M cost equations in the existing model for collection and flaring systems (2008$'s) were escalated to 2013$'s, as shown in Table 3.

Table 3. Collection & Flaring Annual O&M Cost Equations (Escalated from 2008$'s to 2013$'s)

Collection and Flaring O&M Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Collection (excluding energy)[4]	**$2,600 per well**	• Same base equation as existing model, escalated from 2008$'s to 2013$'s ($2,546/well) and then rounded up to be conservative.
Flare (excluding electricity)[4]	**$5,100 per flare**	• Same base equation as existing model, escalated from 2008$'s to 2013$'s ($5,091/flare) and then rounded up to be conservative.

[4] Escalated using default general inflation rate of 2.5%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.

DIRECT-USE SYSTEMS

Due to low natural gas prices, few companies are pursuing direct-use projects in recent years. This trend has resulted in limited cost data for installations of direct-use systems. Cornerstone suggested utilizing the pipeline costs (2010$'s) they provided for the boiler retrofit module that were added to the internal version of LFGcost in 2011. Cornerstone noted that escalating skid and pipeline capital costs by approximately 2% per year is a reasonable estimate based on discussions with contractors and vendors. Therefore, we have escalated cost equations from the existing model to result in updated capital and O&M cost equations for direct-use systems, as shown in Tables 4 and 5, respectively.

Table 4. Direct-use Installed Capital Cost Equations (Escalated from 2008$'s to 2013$'s)

Direct-use Equipment Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Skid-mounted Filter, Compressor, and Dehydration Unit[5, 6]	**($360 * ft^3/min) + $830,000**	• Same base equation as existing model for direct-use systems, escalated from 2008$'s to 2013$'s [($359 * ft^3/min) + $828,061] and then rounded up to be conservative.
Pipeline[5, 6, 7]	**≤1,000 ft^3/min: ($80 * feet) + $178,000** **1,001-3,000 ft^3/min: ($106 * feet) + $207,000**	• Same base equation as existing model for boiler retrofit pipelines, escalated from 2010$'s to 2013$'s as follows and then rounded up to be conservative: ≤1,000 ft^3/min: ($80 * feet) + $177,222 1,001-3,000 ft^3/min: ($106 * feet) + $206,405

[5] ft^3/min = project LFG design flow rate
[6] Escalated using updated default equipment inflation rate of 2%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.
[7] feet = pipeline distance

Table 5. Direct-use Annual O&M Cost Equations (Escalated from 2008$'s to 2013$'s)

Direct-use O&M Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Filter, Compressor, Dehydration Unit, and Pipeline (excluding electricity)[8, 9]	**$57,000 * ($ft^3$/min / 700)$^{0.2}$**	• Same base equation as existing model for direct-use systems, escalated from 2008$'s to 2013$'s [$56,570 * ($ft^3$/min / 700)$^{0.2}$] and then rounded up to be conservative.

[8] ft^3/min = actual LFG flow rate
[9] Escalated using default general inflation rate of 2.5%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.

STANDARD ENGINE-GENERATOR SETS

Cornerstone provided equipment cost data for six standard engine-generator sets installed in 2011-2013. Table 6 provides updated capital cost equations for standard engines (2013$'s) as well as the methodologies used to determine these typical costs.

Table 6. Standard Engine Installed Capital Cost Equations (Based on Installations in 2011-2013)

Engine-Generator Equipment Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Gas Compression/Treatment, Engine/Generator, Site Work, and Housings[10]	**($1,300 * kW) + $1,100,000**	• Total capital costs for engine installations were plotted against kW capacities to determine a best-fit linear equation (R^2 = 0.99, where R^2 = 1.0 represents a perfect fit). • Existing model uses equation of ($1,600 * kW) in 2008$'s. Initially analyzed new cost data to determine if a new "$ per kW" equation could be used but the linear equation provides a more accurate representation of actual costs.
Electrical Interconnect	**$250,000 per system**	• No change from existing model as two 2013 installations had interconnect costs of $250,000 per system.

[10] kW = kW capacity

Table 7 shows a comparison of standard engine capital costs for equations used in the existing model (both 2008$'s and escalated 2013$'s) and the new model.

Table 7. Comparison of Existing Model and New Model Capital Costs for Standard Engines of Varying Sizes

kW Capacity	Total Capital Costs for Standard Engines		
	Existing Model – Baseline (2008$'s)	Existing Model – Escalated[11] (2013$'s)	New Model (2013$'s)
800	$1,280,000	$1,413,223	$2,140,000
1,600	$2,560,000	$2,826,447	$3,180,000
2,400	$3,840,000	$4,239,670	$4,220,000
3,200	$5,120,000	$5,652,894	$5,260,000
4,800	$7,680,000	$8,479,341	$7,340,000
6,400	$10,240,000	$11,305,787	$9,420,000

[11] Escalated using updated default equipment inflation rate of 2%, as documented in Appendix A of the User's Manual for LFGcost-Web Version 3.0.

Cornerstone also provided annual O&M costs for the same six standard engine installations. Table 8 provides an updated annual O&M cost equation for standard engines (2013$'s) as well as the methodology used to determine this typical cost.

Table 8. Standard Engine Annual O&M Cost Equations (Based on Installations in 2011-2013)

Engine-Generator O&M Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Compression/Treatment and Engine/Generator (excluding energy)	**$0.025 per kWh generated**	• O&M costs for engine installations ≥800 kW are \$0.025 per kWh. • Existing model uses equation of \$0.020 per kWh.

ONSITE CNG PRODUCTION AND FUELING STATION

Cornerstone provided capital and annual O&M cost data for 14 onsite CNG production units and fueling stations. Five of these units were installed in 2011-2013, and the remaining were cost estimates utilizing design, permitting, fabrication, and installation costs, adjusted for site-specific conditions. These CNG project installations included the following equipment and services:

- LFG-to-CNG conversion and conditioning unit
- Fueling station equipment – includes compressors, dispensers, and storage tanks for all fill types (fast, slow, combo fast/slow)
- Winterization equipment (if needed) – includes heat tracing and insulation of hydrogen sulfide vessel and heated and insulated structure over other equipment
- Engineering and project management – includes site design, layout, and permitting
- Installation of all equipment, startup, and training

Table 9 provides new capital cost equations for onsite CNG production and fueling (2013$'s) as well as the methodologies used to determine these typical costs.

Table 9. CNG Installed Capital Cost Equations (Based on Installations in 2011-2013)

Onsite CNG Equipment Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
CNG Conversion and Fueling Station[12]	**\$95,000 * $(ft^3/min)^{0.6}$**	• Total capital costs for CNG installations were plotted against LFG design flow rates to determine a best-fit exponential equation (R^2 = 0.90, where R^2 = 1.0 represents a perfect fit). • Capital costs excluded from analysis for one of the 14 projects because fueling station equipment was not included.

[12] ft^3/min = project LFG design flow rate

Table 10 provides a new annual O&M cost equation for onsite CNG production and fueling (2013$'s) as well as the methodology used to determine this typical cost.

Table 10. CNG Annual O&M Cost Equations (Based on Installations in 2011-2013)

Onsite CNG O&M Component	New Typical Cost (2013$'s)	Cost Analysis Methodology
Media and Equipment Replacement and Parasitic Load[13]	**$1.00 per GGE**	• Calculated average cost per GGE for all installations ($0.95/GGE) and then rounded up to be conservative.

[13] GGE = gasoline gallon equivalent; GGE determined assuming an LFG-to-CNG conversion efficiency of 65% and a fuel use rate of 111,200 Btu per gallon of gasoline. To determine $/diesel gallon equivalent (DGE), divide $/GGE by 0.866.

ERG

MEMORANDUM

TO: Hillary Ward, U.S. Environmental Protection Agency, OAQPS/Sector Policies and Programs Division, Fuel and Incineration Group

FROM: Eastern Research Group, Inc. (ERG)

DATE: June 2015

SUBJECT: DRAFT Updated Methodology for Estimating Cost and Emission Impacts of MSW Landfill Regulations

Introduction

The EPA is reviewing the new source performance standards (NSPS) and emission guidelines (EG) for municipal solid waste (MSW) landfills. Currently, the regulations require landfills of at least 2.5 million megagrams (Mg) and 2.5 million cubic meters in design capacity with estimated nonmethane organic compounds (NMOC) emissions of at least 50 megagrams (Mg) per year to collect and control landfill gas (LFG). As part of the proposed revisions, a Microsoft® Access database was developed to calculate the cost and emission impacts associated with varying certain control parameters and applying these parameters to a dataset of existing and model future landfills. The development of the dataset is discussed in other memoranda.[1] The purpose of this memorandum is to summarize the methodology for the evaluations.

1. General Assumptions

The emission reductions and costs associated with the requirements of the current rule are considered the baseline and each alternative was compared to this baseline. All existing landfills that accepted waste after November 1987[2] as well as future landfills that are predicted to open or modify in the 5-year period of January 2014 through December 2018 are included in the analysis. Annual estimates of emission reductions and costs were estimated for each landfill and alternative control scenario in year 2025. Costs were estimated using both a 7 percent and 3 percent interest rate.

The alternatives differ from the baseline by variations in the emission rate thresholds and the design capacity thresholds. Shorter lag times were only evaluated for wet landfills as discussed in another memorandum.[3] A description of each variable is presented below:

- The **emission rate threshold** in the current rule is 50 Mg per year NMOC. The alternatives include lower NMOC thresholds.

[1] ERG. 2014. Summary of Landfill Dataset Used in the Cost and Emission Analysis of Landfill Regulations; ERG. 2015. Summary of Updated Landfill Dataset Used in the Cost and Emission Reduction Analysis of Landfills Regulations. 2015.

[2] The designated facility under the EG is each existing MSW landfill that has accepted waste since November 8, 1987 and for which construction, reconstruction, or modification was commenced on or before July 17, 2014.

[3] ERG. 2015. Revised Cost and Emission Impacts Resulting from the Landfill EG Review.

- The **design capacity threshold** in the current rule is 2.5 million Mg and 2.5 million cubic meters. Other landfill design capacity thresholds were evaluated as alternatives.

- The **initial lag time** is the time period between when the landfill exceeds the emission threshold and when GCCS are required to be installed. The current rule allows a 30-month initial lag time, which was modeled as a 3-year lag time since the first-order decay equation used to model emissions is on an annual, instead of monthly, basis. Further, because the current rule requires annual NMOC emission reports to be submitted by 6 months into the following calendar year, the landfill would get 30 months after the submittal of its first NMOC emission report showing an exceedance to install the GCCS, which is approximately 36 months after the excess emissions occurred. Shorter initial lag times were examined among the alternatives.

- The **expansion lag time** is the amount of time allotted for the landfill to expand the GCCS into waste being placed in new areas of the landfill. The current rule allows 2 years after initial waste placement in closed areas and 5 years after initial waste placement in active areas of the landfill; so the actual lag time varies by landfill depending how quickly expansion areas are filled and closed. Based on input received during public outreach, most modern large landfills do not reach final grade within 2 years and a majority of landfills are complying with the 5 year provision. Therefore, a 4-year expansion lag time was assumed to represent the baseline. A shorter lag time was examined as an alternative.

2. Estimating Emission Impacts

2.1 Waste Estimates

First, the quantity of waste maintained in each landfill was estimated for each year of the analysis, based on one of two methods:

1. For landfills reporting to GHGRP:
   a. Historical annual waste acceptance rate (AWAR) data beginning with the year the landfill opened through 2013 were generally available in GHGRP data tables 'HH_ANN_WASTE_DISPOSAL_QTY' and 'HH_HIST_YR_WASTE_QTY'. These data were used to compute cumulative waste-in-place (WIP) amounts for each year of the model.
   b. If data were missing for 2012 or 2013 reporting years at open landfills, the last known year's AWAR was used to fill data gaps.
   c. To estimate future year AWAR for landfills open past 2013, one of four methods was used:
      i. For landfills with calculated 2013 WIP less than reported landfill capacity:
      AWAR = (Design Capacity - 2013 WIP)/(Estimated landfill closure year - 2013)
      ii. For landfills with calculated 2013 WIP greater than or equal to reported landfill capacity:
      AWAR = 2013 AWAR
      iii. For landfills with calculated future AWAR greater than 10% of the 2013 AWAR:
      AWAR = 2013 AWAR
      iv. For landfills with 2013 AWAR = 0, future annual *AWAR = 0*.
2. For other landfills that were not GHGRP reporters, the landfill waste data were calculated one of two ways:
   a. When a landfill's AWAR and WIP values were available in the landfill dataset and associated with a particular year, those values were extrapolated to estimate the landfill's AWAR and WIP for each year. This estimation method was designated Option A in the database table of Calculated Inputs_Annual Waste.

- When a Landfill_WIP and Landfill_WIP_Year are reported, the AWAR up until the Landfill_WIP_Year is estimated based on the following relationship:
  AWAR = Landfill_WIP / (Landfill_WIP_Year - Landfill _Year_Open+1).
- The AWAR after the Landfill_WIP_Year is based on the following relationship:
  AWAR = (Landfill_Design_Cap_tons - Landfill_WIP) / (Landfill_Closure_Year - Landfill _WIP_Year+1).

2. When WIP and AWAR values were not available in the landfill dataset, the AWAR was estimated using the landfill open and closure years and the landfill capacity and assuming a constant AWAR over the lifetime of the landfill. This estimation method was designated Option D in the database table of Calculated Inputs_Annual Waste.
   - *AWAR = Landfill_Design_Cap_tons / (Landfill_Closure_Year - Landfill _Year_Open+1)*

   Next, the annual WIP was calculated by summing the AWAR over time.

2.2 Emission Equations

After the annual quantity of waste was estimated for each landfill, a first order decay equation (Equation 1) was used estimate annual methane emissions from each landfill for each year. The dataset includes annual emission estimates for 2014-2025-2039.

Eq. 1: $$CH_{4_t} = k \times L_0 \times M \times e^{-kt}$$

Where:

CH_{4t}	=	Methane, ft^3 in year t
k	=	Methane generation rate, $year^{-1}$
L_0	=	Potential methane generation capacity, ft^3 methane per ton
M	=	Mass of waste accepted in year t, tons
t	=	Analysis year (year 1 through 50), year

The volume of LFG produced by a landfill was estimated using Equation 2.

Eq. 2: $$LFG_t = CH_{4t} \times 2$$

Where:

LFG_t	=	Landfill gas, ft^3 in year t
CH_{4t}	=	Methane, ft^3 in year t
2	=	Multiplier to convert methane to LFG (assuming that LFG is 50 percent methane), unitless

The mass of NMOC emissions produced by each landfill was estimated based on the amount of LFG produced at the landfill, as shown in Equation 3.

Eq. 3: $$NMOC_t = LFG_t \div 35.32 \times 595 \times 3.6E^{-9}$$

Where:

$NMOC_t$	=	NMOC in year t, Mg in year t
LFG_t	=	Landfill gas, ft^3 in year t
35.32	=	Conversion, ft^3 per m^3

595	=	Concentration of NMOC in LFG, ppm NMOC by volume as hexane
3.6E-9	=	Conversion factor, Mg NMOC per m^3 LFG

The mass of methane emissions produced by each landfill was estimated based on the volume of methane produced at the landfill, as shown in Equation 4a.

Eq. 4a: $Mg\ CH_4 = CH_{4t} \times 0.0423 \div 2000 \div 0.90718$

Where:

$Mg\ CH_4$	=	Methane in year t, Mg in year t
CH_{4t}	=	Methane, ft^3 in year t (From Equation 1)
0.0423	=	Density of methane, lb per ft^3
2000	=	Conversion, lb per short ton
0.90718	=	Conversion, short ton per Mg

The mass of methane emissions, in terms of carbon dioxide equivalents, produced by each landfill was estimated using the Equation 4b.

Eq. 4b: $Mt\ CO_2eq = Mg\ CH_4 \times GWP_{CH4}$

Where:

$Mt\ CO_2eq_t$	=	Methane emissions as carbon dioxide equivalents, Mt in year t[4]
$Mg\ CH_{4t}$	=	Methane, Mg in year t (From Equation 4a)
GWP_{CH4}	=	25, Global Warming Potential of Methane

2.3 NSPS/EG and AP-42 Default Values for Calculating Emissions[5]

The current NSPS requires the use of Tier 1 default value for the potential methane generation capacity (L_0) and methane generation rate (k) to determine when the landfill exceeds the 50 Mg NMOC per year emission rate threshold. The NSPS L_0 is equal to 5,458 ft^3 methane per ton of waste and the NSPS k values are 0.05 per year for areas receiving 25 inches or more of rainfall per year and 0.02 per year for areas receiving less than 25 inches of rainfall. While the NSPS offers a conservatively high Tier 1 default NMOC concentration, the regulations allow the use of Tier 2 tests to determine NMOC concentration. (Many landfills have conducted Tier 2 tests and gotten values that are consistent with the AP-42 average NMOC concentration of 595 ppmv.) Therefore, the combination of the Tier 1 defaults for k and L_0 and the NMOC concentration of 595 ppmv were used to represent how landfills currently calculate NMOC emissions to determine if they have to install controls under the NSPS. Because the use of these values result in estimates of LFG and NMOC that are in accordance with the current NSPS; in this evaluation these estimates were called $LFG_{NSPS/EG}$ and $NMOC_{NSPS/EG}$. NSPS defaults tend to overestimate actual emissions at most landfills (due to the conservatively high L_0 and k values).

EPA has collected and compiled available emission factor data for landfills in the report *Compilation of Air Pollutant Emission Factors* (AP-42).[6] The AP-42 L_0 is equal to 3210 ft^3 methane per ton of waste. The AP-42 k values are 0.04 per year for areas receiving 25 inches or more of rainfall per year and 0.02 per year for areas receiving less than 25 inches of rainfall. The use of these values, in

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[4] A megagram is equal to a metric ton.

[5] The modeling requirements for existing sources under the state and federal plans implementing the EG are similar to those for new and modified sources under the current NSPS.

[6] USEPA AP-42, Fifth Edition, Volume I Chapter 2: Solid Waste Disposal. http://www.epa.gov/ttn/chief/ap42/ch02/index.html

combination with the NMOC concentration of 595 ppmv, result in estimates of LFG and NMOC that are in accordance with the AP-42; in this evaluation these estimates were called LFG_{AP-42} and $NMOC_{AP-42}$.

As previously mentioned, for this evaluation, $LFG_{NSPS/EG}$ and $NMOC_{NSPS/EG}$ were used to determine when landfills would install controls. To determine when landfills may remove controls, the current rules allow landfills to measure the actual collected gas flow rate as well as the concentration (instead of relying on Tier 1 default L_0 and k defaults). Because the AP-42 values for L_0 and k produce results that more closely match actual gas flow rates and emissions, LFG_{AP-42} and $NMOC_{AP-42}$ were used in this analysis to determine when landfills would remove controls.

Landfill-Specific k Factors

As noted above, the k values depend on the amount of precipitation at the landfill. For this evaluation, long-term precipitation data by county are available for most landfill locations.[7] Some landfills in remote areas or U.S. Territories did not have data available and data from nearby weather stations from the National Oceanic and Atmospheric Administration (NOAA) were obtained and averaged over the available data period for each location.[8] The k factors were assigned to each landfill based on the resulting amount of precipitation at each landfill.

2.4 Emission Reductions

To estimate emission reductions, the amount of LFG, methane, and NMOC emitted at each landfill was estimated using the equations in Section 2.1. After the emissions at each landfill exceed the NMOC emission rate threshold of each control scenario, the model assumed that the collection equipment was installed and operational at the landfill after the initial lag time of the control scenario. For example, if the landfill exceeded the NMOC emission threshold in year 1, and the initial lag time was 3 years, the landfill would begin collecting gas in year 4. As the landfill was filled over time, the model assumed the landfill would expand the GCCS into new areas of waste placement in accordance with the expansion lag time of the control scenario. If the landfill was not expanding the gas collection system (i.e., by installing wells in new areas of waste placement) every year, the landfill may have produced more emissions than could be collected until the gas collection system was expanded.

Once the landfill reached the maximum gas production and the gas production started to decrease, the analysis assumed that the GCCS would collect all of the emitted gas. To determine the amount of LFG, methane and NMOC collected, the analysis used the LFG_{AP-42} and $NMOC_{AP-42,}$ estimates with the appropriate lag times. This was the best estimate of actual gas collected. See Table 1 for an example of the collected gas estimate at a landfill where the initial lag time was 3 years and the expansion lag time was 4 years.

Table 1. Example of Collected NMOC Estimate at a Landfill with an Initial Lag Time of 3 Years and an Expansion Lag Time of 4 Years

Year	$NMOC_{NSPS/EG}$	$NMOC_{AP-42}$	Collected NMOC
1	50.2	27.7	0.0
2	50.4	27.9	0.0
3	50.6	28.0	0.0
4	50.8	28.2	28.2
5	51.0	28.3	28.2

[7] Prism Climate Group. 30-year Normals (1981-2010). http://www.prism.oregonstate.edu/normals/, Accessed September 2015.
[8] NOAA climate division data are available online at: http://www.ncdc.noaa.gov/cdo-web/

6	51.1	28.5	28.2
7	51.3	28.6	28.2
8	51.5	28.7	28.7
9	51.6	28.9	28.7
10	51.7	29.0	28.7
11	51.9	29.1	28.7
12	52.0	29.2	29.2
13	52.1	29.3	29.2
14	52.2	29.4	29.2
15	52.3	29.5	29.2

The emission reductions are equal to the amount of collected NMOC and methane that is combusted. The amount of collected NMOC and methane destroyed by combustion controls was estimated by multiplying the amount of collected gas by a destruction efficiency of 98 percent. The 98 percent destruction efficiency accounts for the fact that combustion is not 100 percent efficient.

3. Cost Equations

The cost equations used in this regulatory evaluation were derived from EPA's Landfill Gas Energy Cost Model (LFGcost-Web), version 3.0, which was developed by EPA's Landfill Methane Outreach Program (LMOP). LFGcost-Web estimates costs for gas collection, flare and energy recovery systems and was developed based on cost data obtained from equipment vendors and consulting firms that have installed and operated numerous gas collection and control systems. LFGcost-Web encompasses the types of costs included in the EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual including capital costs, annual costs, and recovery credits. Total capital costs include purchased equipment costs, installation costs, engineering and design costs, costs for site preparation and buildings, costs of permits and fees, and working capital. Total annual costs include direct costs, indirect costs, and recovery credits. Direct annual costs are those that are proportional to a facility-specific metrics such as the facility's productive output or size. Indirect annual costs are independent of facility-specific metrics and may include categories such as administrative charges, taxes, or insurance. Recovery credits are for materials or energy recovered by the control system.

For this evaluation, all costs are presented in 2012$. The costs included in LFGcost-Web are in 2013$ and were adjusted to 2012$ using a factor of 2 percent for capital costs and 2.5 percent for O&M costs.

The analysis presents the annualized capital cost of flares, wells, wellheads (including piping to collect gas) and engines over the lifetime of the equipment. It was assumed that the equipment would be replaced when its lifetime was over, so the annualized capital costs were incurred as long as the landfill still had controls in place. In order to calculate the annualization factors, it was assumed that flares, wells, well heads, and engines had a 15-year lifetime. In addition, there was a mobilization/installation charge to bring well drilling equipment on site each time the gas collection system was expanded. Because the landfill would be drilling wells to expand the control system during the expansion lag year, it was assumed that this capital installation cost had a lifetime equal to the expansion lag time.

A number of the capital costs equations depend on the number of wells at each landfill. In order to estimate the number of wells at each landfill, the number of acres that have been filled with waste for each landfill for each year were estimated. For landfills not reporting a GCCS area to GHGRP, it was assumed that the percent of design area filled (acres) would track the ratio of waste in place/design capacity (e.g., if a landfill had a waste-in-place amount equivalent to 40 percent of design capacity, then 40 percent of the planned acreage would be filled). For GHGRP landfills who reported a GCCS area (as discussed in section 2.3 of another memorandum)[9] this value was compared to the calculated area based on ratio of waste in place/design capacity discussed above. The maximum of the reported value or this calculated area was used as the starting point for an estimated GCCS area in year 2014, and that area grew overtime, tracking the ratio of waste in place/design capacity. In addition, it was assumed that each landfill would install one well per acre, consistent with the guidelines provided in the LFGcost-Web model, and that the number of wells would increase periodically based on expansion lag time. See Table 2 for an example of the number of wells estimated annually at a landfill where the initial lag time is 3 years and the expansion lag time is 4 years.

Table 2. Example of Number of Wells at a Landfill with an Initial Lag Time of 3 Years and an Expansion Lag Time Equal to 4 Years (and the landfill reaches the emission rate threshold in year 1)

Year	Acreage	Number of Wells
1	98.2	0
2	102.9	0
3	107.5	0
4	112.1	112
5	116.8	112
6	121.4	112
7	126.1	112
8	130.7	131
9	135.4	131
10	140	131
11	140	131
12	140	140
13	140	140
14	140	140
15	140	140

3.1 Capital Costs

The equations used in this evaluation to calculate capital costs for flares, wells, wellheads (including gas collection piping), mobilization/installation, and engines are presented below. All costs equations are shown on an individual landfill and year basis.

Flare Capital Costs

Flares are the primary control device used at landfills. All landfills required to comply with the control scenario were assumed to install flares. Landfills using engines were assumed to have flares as the back-up control device for periods when the engines are not operating. The capital flare costs were estimated using the equation below, which was based on the installed cost of the knockout, blower, and flare system as determined in LFGcost-Web. The flares were sized based on the maximum LFG flow rate over the 15-year flare lifetime, which could be as late as 2039 for projects that were expected to begin operation in 2025.

$$\textbf{Eq. 5}:\quad \text{Flare}_{\text{capital}} = z_{\,15,y} \times \left(\frac{\text{LFG}_{\text{15yr max}}}{525{,}600}\right)^{0.61} \times 4{,}600 \times (1.02)^{-1}$$

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[9] Summary of Updated Landfill Dataset Used in the Cost and Emission Reduction Analysis of Landfills Regulations. 2015.

Where:

$Flare_{capital}$	=	Installed annualized cost of knockout, blower, and flare system, 2012$
$z_{15,y}$	=	Annualization factor where x=15 yrs and y=interest rate (0.07 or 0.03), unitless
$LFG_{15yrmax}$	=	Maximum LFG collected for 15 year project period, ft^3 per year
525,600	=	Conversion factor, minutes per year
$4,600	=	Installed capital cost of knockout, blower, and flare system, 2013$ per ft^3/min LFG
$(1.02)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless[10]

Vertical Gas Extraction Well Capital Costs

The vertical gas extraction well capital costs were based on a dollar per linear foot of well depth installed estimate from LFGcost-Web. As shown in the equation below, wells were assumed to have a depth of 10 feet less than the landfill depth. The method used to estimate the number of wells at the landfill each year is described above.

Eq. 6: $$Well_{capital} = z_{15,y} \times (Depth - 10) \times 85 \times Wells_{annual} \times (1.02)^{-1}$$

Where:

$Well_{capital}$	=	Installed annualized cost of vertical wells, 2012$
$z_{15,y}$	=	Annualization factor where x=15 yrs and y=interest rate (0.07 or 0.03), unitless
Depth	=	Landfill waste depth, feet
10	=	feet
$85	=	Installed capital cost of one vertical well, 2013$ per foot of well depth
$Wells_{annual}$	=	Number of vertical wells operated each year
$(1.02)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless

Wellhead Capital Costs

The capital wellhead cost covered the equipment associated with each well, including the wellhead and pipe gathering system (and any additional fittings/installations connecting the wells, and was dependent on the number of wells. In addition, this capital cost encompasses engineering, permitting, and surveying fees associated with the wellfield installation that are also dependent on the number of wells. The capital wellhead costs at each landfill were estimated using a dollar per well installed cost from LFGcost-Web for wellheads, pipe gathering system, engineering, permitting, and surveying and the number of wells at each landfill.

Eq. 7: $$Wellhead_{capital} = z_{15,y} \times 17{,}700 \times Wells_{annual} \times (1.02)^{-1}$$

Where:

$Wellhead_{capital}$	=	Installed annualized cost of wellheads, 2012$
$z_{15,y}$	=	Annualization factor where x=15 yrs and y=interest rate (0.07 or 0.03), unitless
$17,700=		Installed capital cost of one wellhead, 2013$ per well
$Wells_{annual}$	=	Number of wells operated each year

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[10] Equation uses a formula of $(1+\text{inflation rate}/100)^t$, where capital cost escalation is assumed to be 2 percent and t is equal to -1 year

$(1.02)^{-1}$ = Adjustment from 2013$ to 2012$, unitless

Mobilization/ Installation Costs for Wellfield Expansion

The cost occurs upon installation of a new gas collection system (i.e., wellfield) and each time the wellfield was expanded into new areas of the landfill, so the frequency was dependent on the expansion lag time. This cost was independent of the number of wells being added. It included costs such as planning, set-up, and mobilization costs to get the well drilling rig and pipe crew on site. This cost was estimated using the following equation from LFGcost-Web:

Eq. 8: $$\text{Installation}_{\text{capital}} = z_{x,y} \times 20{,}000 \times (1.02)^{-1}$$

Where:

$\text{Installation}_{\text{capital}}$ = Mobilization/installation annualized cost, 2012$
$z_{x,y}$ = Annualization factor where x=expansion lag time in yrs and y=interest rate (0.07 or 0.03), unitless
$20,000 = Mobilization/Installation costs, per occurrence, 2013$
$(1.02)^{-1}$ = Adjustment from 2013$ to 2012$, unitless

Engine Capital Costs

Engines were assumed to be installed only at landfills that produced enough LFG to power the engine and only when the electricity buyback rates allowed the operation of the engine to be profitable. Standard engines used at landfills have approximately 1 MW capacity, which equates to 195 million ft^3 per year of collected LFG (at 50 percent methane). Therefore, engines were assumed to be installed at landfills that had at least 195 million ft^3 per year of collected LFG for at least 15 years, which could be as late as 2039 for engines there were installed in 2025.

The engine capital and operation and maintenance (O&M) equations were calculated and summed to determine at what electricity buyback rate an engine would be profitable. The profitable electricity buyback rate was greater than $0.0594 per kWh at a 7 percent interest rate and greater than $0.0430 per kWh at a 3 percent interest rate; it was assumed engines were only installed in States with buyback rates exceeding those values.

Multiple engines may be present at a landfill when there is sufficient gas flow to support additional engines. As noted above, one engine required 195 million ft^3 per year of collected LFG. To have two engines on site, the landfill must have had double that amount of LFG (390 million ft^3 per year) for at least 15 years after the project start date, which could be as late as 2037 for projects starting in 2023.

The capital costs for engines were based on the capital costs for standard reciprocating engine-generator sets in LFGcost-Web. These costs included gas compression and treatment to remove particulates and moisture (e.g., a chiller), reciprocating engine and generator, electrical interconnect equipment, and site work including housings, utilities, and total facility engineering, design, and permitting.

$$\textbf{Eq. 9}: \quad \text{Engine}_{\text{capital}} = z_{15,\,y} \times 2{,}650{,}000 \times (1.02)^{-1} \times \text{Engine}_{\text{multiplier}}$$

Where:

$\text{Engine}_{\text{capital}}$	=	Installed annualized cost of engines, 2012$
$z_{15,y}$	=	Annualization factor where x=15 yrs and y=interest rate (0.07 or 0.03), unitless
$2,650,000	=	Installed capital cost of one reciprocating engine-generator set, 2013$ per engine
$(1.02)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless
$\text{Engine}_{\text{multiplier}}$	=	Number of engines needed

3.2 Operation and Maintenance (O&M) Costs

The equations used in this evaluation to calculate O&M costs for flares, wells, electricity, and engines are presented below. All cost equations are shown on an individual landfill and year basis. These costs for all landfills were summed by year and the resulting annual sums were used to estimate NPV costs.

To accurately estimate annual electricity costs and engine revenue from the generation and sale of electricity, two electricity prices were needed. Landfills must purchase electricity to operate the blowers used to collect LFG. EPA used 2012 commercial average retail electricity prices by State from the U.S. Energy Information Administration (EIA) to estimate electricity purchase prices at the landfill[11].

Landfills utilizing engines generate revenue from the sale of the LFG-produced electricity. The amount of revenue generated depends primarily on the buyback rate negotiated between the landfill (or third party developer) and the electric company purchasing the LFG-generated power. Average (mean) wholesale prices for each State were calculated using 2012 resale generation and revenue data from EIA to estimate electricity buyback rates[12]. These wholesale prices generally fit in the range of typical buyback prices for LFG of $0.025 - $0.11/kWh, as discussed in LMOP's Project Development Handbook.[13] Additionally, LFGcost-Web uses a default buyback rate of $0.06/kWh and the U.S. average of the wholesale prices used is $0.0655/kWh.

EIA wholesale data were not available for three States (HI, RI, & WV). For these States, electricity purchase price data from EIA were used to estimate buyback rates[14]. The buyback rates were estimated by first determining the ratio of each State's purchase price to the overall average U.S. purchase price. This ratio was then multiplied by the calculated average U.S. wholesale price to estimate a buyback rate. Electricity price data for the U.S. territories of Guam, Puerto Rico, and the Virgin Islands were not found. Therefore, EIA profile analyses for these three territories were used to escalate U.S. average prices to estimate electricity prices for each island[15].

Flare O&M Costs

[11] U.S. DOE/EIA. Electricity: Detailed State Data, Annual Data for 2012. Average Price by State by Provider (EIA-861), 1990-2012. Released November 12, 2013. http://www.eia.gov/electricity/data/state

[12] U.S. DOE/EIA. Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files. 2012 Operational Data (Formerly File 1). Released October 29, 2013. http://www.eia.gov/electricity/data/eia861

[13] U.S. EPA LMOP Chapter 4 of Project Development Handbook. http://epa.gov/lmop/documents/pdfs/pdh_chapter4.pdf

[14] U.S. DOE/EIA. Electricity: Detailed State Data, Annual Data for 2012. Average Price by State by Provider (EIA-861), 1990-2012. Released November 12, 2013. http://www.eia.gov/electricity/data/state

[15] U.S. DOE/EIA. Territory Profile and Energy Estimates (for Guam, Puerto Rico, and the U.S. Virgin Islands). Profile Analysis, Electricity. December 18, 2013. http://www.eia.gov/state

An estimate of the flare O&M costs from LFGcost-Web was used to estimate the flare annual costs, as shown in the equation below:

$$\textbf{Eq. 10}: \text{Flare}_{\text{O\&M}} = 5{,}100 \times (1.025)^{-1}$$

Where:

$\text{Flare}_{\text{O\&M}}$	=	Flare annual O&M costs, 2012$
$5,100	=	Annual O&M flare cost, 2013$
$(1.025)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless[16]

Well O&M Costs

An estimate of the O&M costs for vertical gas extraction wells from LFGcost-Web was used to estimate the well annual costs, as shown in the equation below:

$$\textbf{Eq. 11}: \text{Well}_{\text{O\&M}} = 2{,}600 \times \text{Wells}_{\text{annual}} \times (1.025)^{-1}$$

Where:

$\text{Well}_{\text{O\&M}}$	=	Well annual O&M costs, 2012$
$2,600	=	Annual O&M well costs, 2013$ per well
$\text{Wells}_{\text{annual}}$	=	Number of wells operating each year
$(1.025)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless

Electricity O&M Costs

The electricity cost of operating the blowers was calculated using the electricity usage of blowers from LFGcost-Web and the electricity purchase price.

$$\textbf{Eq. 12}: \text{Electricity}_{\text{O\&M}} = 0.002 \times \text{Electricity}_{\text{purchase}} \times \text{LFG}_{\text{collected}}$$

Where:

$\text{Electricity}_{\text{O\&M}}$	=	Electricity annual O&M costs, 2012$
0.002	=	Electricity usage by blowers, kWh per ft^3 LFG
$\text{Electricity}_{\text{purchase}}$	=	Electricity purchase price, 2012$ per kWh
$\text{LFG}_{\text{collected}}$	=	Amount of LFG collected, ft^3 per year

Engine O&M Costs

For landfills with engines installed, the O&M costs of the engine were estimated using the annual costs for standard reciprocating engine-generator sets from LFGcost-Web, and taking into account the amount of time that the engine was operating each year (assumed gross capacity factor in LFGcost-Web for engines) and the number of engines on site.

$$\textbf{Eq. 13}: \text{Engine}_{\text{O\&M}} = 0.025 \times 1{,}000 \times 8{,}760 \times 0.93 \times (1.025)^{-1} \times \text{Engine}_{\text{multiplier}}$$

Where:

$\text{Engine}_{\text{O\&M}}$	=	Engine annual O&M costs, 2012$
0.025	=	Annual O&M engine cost, 2013$ per kWh

[16] Equation uses a formula of $(1+\text{inflation rate}/100)^t$, where O&M cost escalation is assumed to be 2.5 percent and t is equal to -1 year.

1,000	=	Amount of electricity as kW produced by a 1 MW engine, kW per engine
8,760	=	Conversion factor, hours per year
0.93	=	Fraction of time that the engine is online, unitless
$(1.025)^{-1}$	=	Adjustment from 2013$ to 2012$, unitless
$\text{Engine}_{\text{multiplier}}$	=	Number of engines

Engine Revenue Costs

For landfills with engines installed, the revenue of the electricity produced by the engines was calculated using the equation below. This equation assumed that all electricity generated was sold to the grid (instead of some of the electricity generated being used to power the GCCS).

Eq. 14: $\text{Engine}_{\text{revenue}} = 1{,}000 \times 8{,}760 \times 0.93 \times \text{Electricity}_{\text{buyback}} \times \text{Engine}_{\text{multiplier}}$

Where:

$\text{Engine}_{\text{revenue}}$	=	Engine annual revenue, 2012$
1,000	=	Amount of electricity as kW produced by a 1 MW engine, kW per engine
8,760	=	Conversion factor, hours per year
0.93	=	Fraction of time that the engine is online, unitless
$\text{Electricity}_{\text{buyback}}$	=	Electricity buyback rate, 2012$ per KWh
$\text{Engine}_{\text{multiplier}}$	=	Number of engines

4. Summary

This memorandum summarizes the emission reduction and cost equations used to evaluate the cost and emission impacts of various control scenarios considered under the review of the NSPS and EG. The EPA determined which landfills met the design capacity and emission rate thresholds for each regulatory option, then calculated the emission reductions and costs for each landfill in 2025 under each control scenario using the equations described in this memorandum. The results of applying this methodology to the landfills dataset are discussed in other memoranda and are detailed in the database.[17, 18, 19, 20]

[17] ERG. 2015. Updated Cost and Emissions Impacts Resulting from the Landfills NSPS Review.

[18] ERG. 2015. Modeling Database Containing Inputs and Results of Supplemental Proposal for MSW Landfill NSPS.

[19] ERG. 2015. Revised Cost and Emission Impacts Resulting from the Landfill EG Review.

[20] ERG. 2015. Modeling Database Containing Inputs and Results for Proposed Review of the MSW Landfill Emission Guidelines.