NICHOLAS INSTITUTE REPORT

A Spatial-Economic Optimization Study of Swine Waste-Derived Biogas Infrastructure Design in North Carolina

Darmawan Prasodjo
Tatjana Vujic
David Cooley
Ken Yeh
Meng-Ying Lee

April 2013

Duke
NICHOLAS INSTITUTE
FOR ENVIRONMENTAL POLICY SOLUTIONS

NI R 13-02

A SPATIAL-ECONOMIC OPTIMIZATION STUDY OF SWINE WASTE–DERIVED BIOGAS INFRASTRUCTURE DESIGN IN NORTH CAROLINA

Darmawan Prasodjo*
Tatjana Vujic†
David Cooley†
Ken Yeh*
Meng-Ying Lee*

*Nicholas Institute for Environmental Policy Solutions, Duke University

† Duke Carbon Offsets Initiative, Duke University

Acknowledgments

The authors thank Brian Duff, Jeff Hughes, Eric Toone, C.M. Williams, Kelly Zering, and Piedmont Natural Gas for their assistance with this paper. We are also grateful to Duke Energy Carolinas and the Environmental Defense Fund for their support of this project.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In an effort to accelerate the deployment of swine waste to energy (WTE) in North Carolina, Duke University researchers set out to determine the optimal approach and configuration of swine operations for the production of electricity from swine waste-derived biogas. Using the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS) as a production target, researchers applied the OptimaBIOGAS model, an iterative geospatial and economic analysis, to optimize the configuration of swine WTE production on the basis of the levelized cost of electricity (LCOE) of specific production scenarios, including on-farm and centralized options.[1] Researchers were particularly interested in options involving "directed biogas" or injection of biogas into natural gas pipelines.[2] This report highlights the importance of systematic planning for swine biogas WTE. Economies of scale could provide incentives to the swine industry, utilities, and third-party entities to invest in biogas-to-electricity generation systems.

Using the OptimaBIOGAS tool, researchers evaluated four options:

1. On-farm electricity production;
2. On-farm biogas collection and pipeline injection ("individual farm-directed biogas");
3. Centralized electricity production at a hub supplied with biogas from a high-density cluster of swine operations ("centralized electricity production"); and
4. Injection of biogas into the natural gas pipeline from a centralized gas pressurization and cleaning station supplied with biogas from a high-density cluster of swine operations ("centralized directed biogas").

Using the LCOEs derived for each scenario, the researchers ranked them on the basis of cost-effectiveness, testing mixed digesters against covered lagoons as well as high versus low cost estimates for inter-farm biogas transport and pipeline injection. Of the four scenarios, the most cost-effective were centralized directed biogas and on-farm electricity production; estimated costs for the former were sometimes nearly half those of on-farm production, where in-ground ambient temperature mixed anaerobic digesters were assumed to be in use. Overall, the costs of the directed biogas scenario, which was the most cost-effective scenario in many cases, ranged between $0.111/kilowatt hour (kWh) and $0.058/kWh. Figure 1 illustrates the range of LCOEs for on-farm electricity production and centralized directed biogas, including costs projected for covered lagoons and mixed in-ground ambient-temperature anaerobic digesters. High and low pipeline costs are factored into the centralized directed-biogas option.

---

[1] N.C. G.S. § 62-133.8.

[2] In March 2012, the North Carolina Utilities Commission approved the use of directed biogas to generate renewable energy certificates for compliance with the REPS on the basis of the biogas' electricity-generating potential, The biogas' electricity generating potential is based on the assumption that it will be used to fuel a natural gas-powered facility, thereby greatly increasing the electricity generation potential of the biogas as compared with on-site power generation.

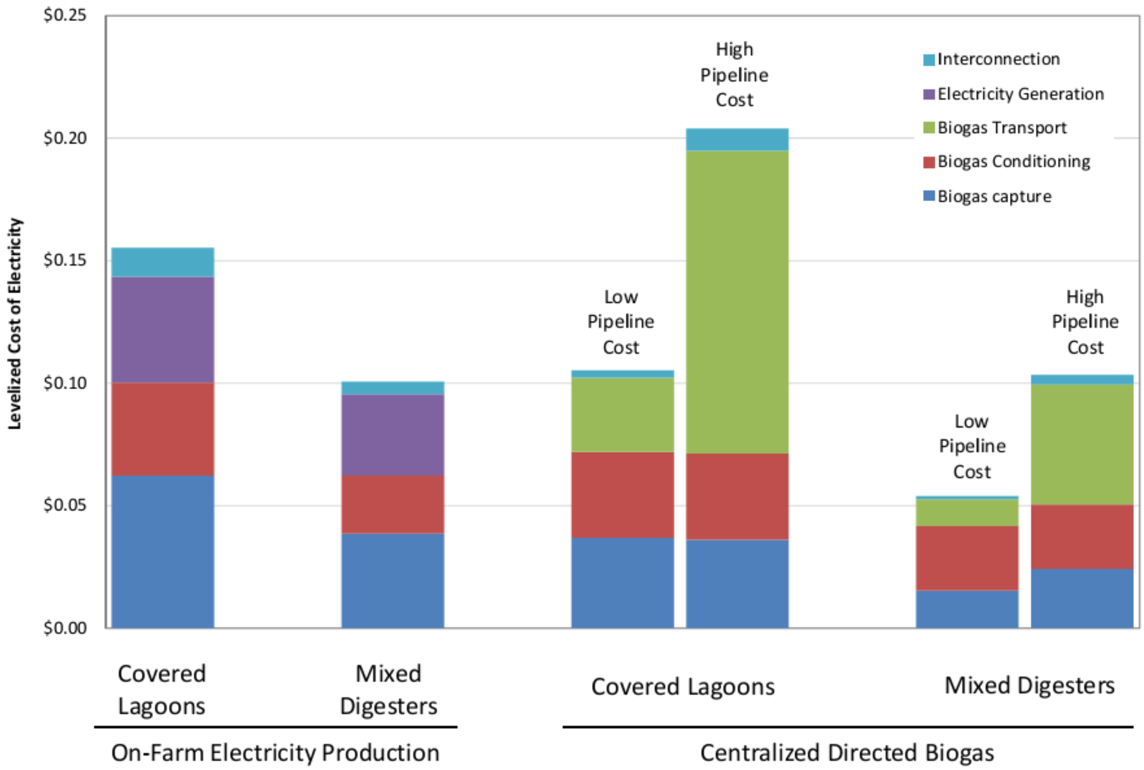


Figure 1. Levelized cost of electricity (LCOE) for the two scenarios with the lowest LCOEs (on-farm electricity production and centralized directed biogas).[3]

Regarding siting, the model identified an area covering portions of Duplin and Sampson counties, in which are located the largest and highest density of swine operations, as the most cost-effective location for generating swine WTE. Importantly, because various options were modeled under each scenario to evaluate energy production potential and costs (e.g., costs and biogas output of mixed digesters versus covered-lagoons and directed biogas versus on-farm electricity production), the analysis did not identify a single winning scenario. Instead, the analysis provided a range of costs and configurations that can provide directional guidance for devising a strategy for swine WTE deployment. This strategy will depend to a large extent on the cost to transport biogas and inject it into the natural gas pipeline.[4]

[3] LCOEs presented here are for biogas systems that would meet the requirements of all three REPS stages, and they include the capital and operating costs over a 20-year period. The scenarios include LCOEs calculated when covered lagoons are used and when mixed digesters are used to capture the biogas at each farm. The centralized directed-biogas scenario includes LCOEs calculated with low-end and high-end pipeline costs

[4] For example, on the basis of the LCOE determined for each scenario and within the two most-cost-effective scenarios for mixed digesters and covered lagoons, researchers could pinpoint the specific swine operations that should be targeted for swine WTE or that should participate in a centralized swine WTE system. In the case of centralized electricity and directed biogas systems, researchers were also able to determine the optimal configuration of the inter-farm biogas pipeline system. Researchers then applied high- and low-end cost estimates for pipeline construction and transport to ascertain the range of costs to generate electricity through a directed biogas approach and a centralized electricity production approach for each stage of the REPS. On the basis of these various factors, researchers determined the range of costs that can be expected to develop swine WTE,

Thus, the LCOEs produced by this analysis provide a way to discern the optimal configurations and approaches for swine WTE. Because the analysis contemplates electricity generation but not business costs (e.g., profits that would motivate investment in development of new systems, payments to swine producers to secure long-term biogas production, or other incentives), it does not represent retail or final costs. Rather, the analysis reflects the costs that researchers estimate would be incurred to supply the market. In actuality, a great deal will depend on how projects are implemented, which may include a combination of the options considered in this study as well as options that may emerge as technologies and processes improve, and on other factors that cannot be predicted.

Finally, in addition to evaluating the cost-effectiveness of various scenarios for meeting the REPS, the analysis considered the greenhouse gas emission reduction potential (and income) from swine WTE and the cost to achieve the environmental performance standards that would qualify the systems as innovative animal waste management systems. These systems carry multiple environmental benefits and would allow participating farms to expand their operations. With respect to greenhouse gas (GHG) emissions, researchers determined that the capture and destruction of swine waste-derived biogas, comprised of approximately 50–60% methane—a greenhouse gas 21 times more potent than carbon dioxide in terms of global warming potential—could reduce emissions by 1.35 to 1.37 million metric tons of carbon dioxide equivalent ($MTCO_2e$) per year, assuming full implementation of the REPS swine set-aside by 2018.[5]

Finally, with respect to the environmental performance standards required by North Carolina for swine farm expansion, researchers considered add-on technologies for the two most cost-effective scenarios (centralized directed biogas and on-farm electricity production)—technologies that would qualify the farms' waste management processes as innovative animal waste management systems in accordance with North Carolina's Swine Farm Environmental Performance Standards Act.[6] Researchers considered these costs because of the opportunity to combine swine WTE with components of innovative animal waste management systems that would significantly improve the overall environmental performance of participating swine operations.[7] Notably, these systems offer more than environmental and health benefits, including potential significant annual public health savings.[8] They also could allow target farms

depending on the approach employed, and found that costs were most heavily influenced by low-pressure pipeline construction, operational and maintenance costs and injection costs. For instance, regarding the range of costs identified for the most efficient configuration of farms for each option evaluated, researchers projected that costs to produce swine WTE would be $0.111/kilowatt-hour (kWh) if an individual farm electricity production option were pursued and *the highest cost projections for pipeline transport and injection costs were assumed* (based on cost estimates received from industry sources for biogas transport and injection into the natural gas pipeline). By contrast, *assuming the lowest cost projections for pipeline transport and injection*, a centralized directed biogas approach that includes mixed anaerobic digestion of the waste could cut costs by nearly half, reducing the projected LCOE to $0.058/kWh.

[5] This estimate assumes that biogas would be generated at each farm, either through the process of anaerobic digestion in a covered lagoon from 284 farms or using in-ground ambient temperature mixed anaerobic digesters on only 127 farms.

[6] Innovative animal waste management systems are defined as systems that substantially reduce ammonia emissions, nutrients, pathogens, heavy metals, and odors and that ensure zero discharge of waste-to-surface water and groundwater. N.C. G.S. § 143-215.10I.

[7] The components included in the modeling analysis were based on the innovative animal waste management system installed at Loyd Ray Farms in Yadkin County, North Carolina. This system aerates the effluent from the digester to foster a population of bacteria that reduces the concentration of ammonia in the wastewater, while also reducing pathogens and odors. For more information on the Loyd Ray Farms system, see the *Data Inputs* section below.

[8] Research suggests that a 50 percent reduction in ammonia emissions from North Carolina swine farms could result in $189 million per year in health benefits. See Brian C. Murray, George L. Van Houtven, Marion E. Deerhake, et al., "Benefits of

to expand, thereby increasing biogas output on a per farm basis and decreasing the number of total farms that would be required to meet the REPS. Farm expansion also can be beneficial to swine producers and integrators because it can increase farm output. For the purposes of this analysis, economic benefits associated with environmental improvements made possible by innovative animal waste management systems were not monetized. Rather, researchers focused solely on determining the additional costs of components and operation and maintenance costs to meet environmental performance standards on a per kilowatt-hour basis, which ranged between approximately \$0.022/kWh and \$0.035/kWh for centralized directed biogas and on-farm electricity production scenarios, respectively.

Study Limitations

The study is a directional one in that it is intended to serve as the first step in developing an informed strategy that would increase the scale of swine WTE production in North Carolina. As such, it should be considered a technical feasibility analysis of the optimization of the swine WTE resource *and not as an absolute predictor of price*. The study does not include a business plan for implementation; therefore, it does not include certain costs, such as the internal rate of return that may be required by project developers or intermediaries to pursue projects. It also does not contemplate payments to swine producers for biogas supply. In addition, the analysis does not include costs to land apply or otherwise dispose of effluent from anaerobic digesters. Therefore, the modeling exercise should be considered a presentation of the basic and relative costs associated with the four evaluated scenarios and should be reviewed with the understanding that the derived LCOEs represent a best rough estimate of costs. Actual implementation costs may reflect other costs not discernible at this point. Additional study based on reasonable business model scenarios could further refine cost projections and develop more precise estimates of the LCOEs, as discussed below and in Section 4. In addition, because the LCOEs presented in this study are optimized across all swine biogas opportunities in North Carolina, nonparticipation by one or more of the selected swine operations might result in pursuit of suboptimal opportunities, resulting in changes to the LCOE.

Further Recommended Analysis

The researchers recognize that further analysis would be helpful to increase the accuracy of cost estimates and to evaluate additional options. Among the topics recommended are:

- Determination of the point at which pursuing a pipeline or centralized approach is more expensive than pursuing individual farm electricity production: This determination allows identification of the price point beyond which centralized electricity production should not be pursued.
- Consideration of monetary benefits associated with installation of innovative animal waste management systems and consideration of which operations would be most likely to adopt innovative animal waste management systems because of aging lagoons or market opportunities that would counsel for expansion. Expansion of specific farms could increase biogas output on a per-farm basis and hence affect the overall cost of electricity production.

Adopting Environmentally Superior Swine Waste Management Technologies in North Carolina: An Environmental and Economic Assessment." Report from RTI International to C.M. Williams, North Carolina State University, 2003.

- Consideration of opportunities for co-digestion of swine waste with other waste streams, such as food waste or other agricultural wastes, which could produce more energy per unit of volume than swine waste digestion alone.
- Further refinement of cost estimates to improve the accuracy of the LCOEs derived by the model and, in particular, to better determine the actual retail cost of electricity to consumers: Such analysis would include development of a business plan or business model to ascertain the full array of costs beyond basic equipment, construction, and operation and maintenance costs associated with each scenario. These other costs include profits, payments to swine producers, and incentive payments.
- Consideration of various business models and financing approaches that would support the implementation of the scenarios identified by the OptimaBIOGAS analysis: One form of support would be determination of a price for swine-based renewable energy certificates (RECs) adequate to encourage development of the resource. That price should reflect an appropriate price for payments or other incentives to swine producers that ensures a sufficient and certain supply of biogas. Such pricing projections also should account for income to project developers and system operators, who will be responsible for implementing and maintaining systems to scale.

Additional recommendations for further analysis are discussed in Section 4.

1. OVERVIEW

North Carolina, as the second largest pork producer in the United States, is home to 2,126 permitted industrial swine operations, which house nearly 9 million animals (Figure 2). The waste from farms that were determined to produce 7,500 MMBtu/year or more of biogas has the potential to produce 19.5 M MMBtu/year and support between 45 and 80 MW of capacity, which could generate between 391 and 703 gigawatt-hours (GWh) of electricity per year.[9] Figure 2 illustrates the location and density of swine operations and biogas potential across North Carolina.

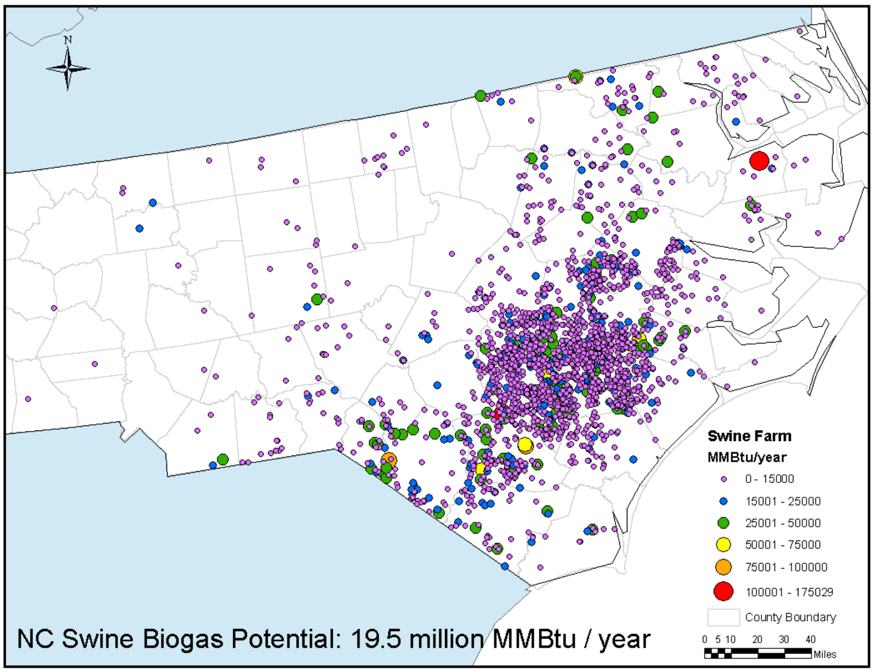


Figure 2. North Carolina biogas potential in million British thermal units (MMBtu)/year.

Recognizing swine waste's potential as a renewable energy source, North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS) mandates that North Carolina utilities source 0.07%, 0.14%, and 0.20% of their electricity on an annual basis from swine waste by 2013, 2015, and 2018and thereafter, respectively. To comply with the REPS, utilities must generate or obtain renewable energy certificates (RECs); each REC represents one MWh of renewable energy generation. The swine waste requirement translates to the production of approximately 90,000 megawatt-hours (MWh) of electricity or RECs per year by 2013, approximately 180,000 MWh per year by 2015, and approximately 270,000

[9] This estimate reflects the assumption that (1) biogas is generated at each farm using mixed digesters and is used to generate electricity in an on-farm microturbine or sent to a more efficient combined-cycle power plant for electricity generation, and (2) the farms participating will generate more than 7,500 MMBtu/year of biogas, a threshold chosen by researchers that reflects their assumption that swine operations with biogas potential below this number would not be practical—or large enough—to pursue swine WTE on a cost-per-MMBtu basis. The estimate also reflects the assumption that microturbines would be used for on-farm generation because they can withstand higher levels of impurities, such as hydrogen sulfide, than internal-combustion engines and therefore would have lower operating costs. For more information on the total swine biogas potential in North Carolina see Section 3. Note that this estimate is slightly lower than the U.S. EPA's biogas potential estimate of 1,121 GWh/year. See U.S. EPA, *Market Opportunities for Biogas Recovery Systems*, http://www.epa.gov/agstar/documents/Market_Opps_Fact_Sheet.pdf.

MWh per year by 2018 (Table 1). Despite the mandate, very few RECs have been generated from swine waste, leading utilities to petition the North Carolina Utilities Commission (NCUC) to extend the deadline for the first phase of the REPS for swine.[10] In March 2012, the NCUC granted an extension of the initial swine waste set-aside from 2012 to 2013.[11] Although anecdotal evidence suggests that project developers have attempted to pursue multi-operation approaches to swine WTE, no formalized strategy takes advantage of the state's high density of swine operations and centralized energy-production potential to harness economies of scale to achieve the most cost-effective deployment swine WTE.

Table 1. NC REPS requirements for electricity generated from swine waste (MWh/year), by REPS target date.

REPS Stage	Year	REPS Requirement (% of Retail Electricity Sales)	Estimates of Energy Required to Meet the REPS		
			MWh/year	Capacity (MW)	MMBtu/year
1	2013	0.07%	90,000	10.3	648,000–927,000
2	2015	0.14%	180,000	20.5	1,296,000–1,854,000
3	2018	0.20%	270,000	30.8	1,944,000–2,781,000

Recognizing the lack of a strategy for swine WTE, Duke University researchers developed and applied the OptimaBIOGAS modeling tool to examine options for utilizing economies of scaleby centralizing energy production to reduce costs of WTE implementation. They also compared centralized options to on-farm production options. Researchers were particularly interested in understanding the implications of the NCUC's directed biogas ruling, which allows injection of biogas into the natural gas pipeline to generate renewable energy certificates in compliance with the REPS. The OptimaBIOGAS analysis uses a series of iterative spatial and economic optimization exercises to identify the most efficient location and configuration of biogas resources (i.e., swine operations) that result in the least-cost options for swine waste-derived electricity production, in this case for compliance with the REPS requirements.[12] The model specifically seeks economies of scale that can increase efficiency and reduce overall costs. By undertaking the analysis, the researchers intended to provide a roadmap by which developers and other stakeholders could efficiently and cost-effectively deploy swine waste-derived biogas resources.

2. METHODS

Study Limitations

This study is intended to serve as the first step in developing an informed strategy to increase the scale of swine WTE production in North Carolina and should be considered a technical feasibility analysis of the optimization of the swine WTE resource. Because the study does not include a business plan for

[10] Despite the REPS swine waste mandate and the ample supply of swine waste in the state, a very small percentage of the set-aside has been fulfilled. According to the most recent public data from the North Carolina Renewable Energy Tracking System (NCRETS), only 7,826 RECs from swine waste generation were registered in the 2008–2011 period; this figure represents only 9% of the requirement for the initial year of compliance.

[11] The NCUC has granted the utilities' request that the start of the REPS requirements for swine waste-derived energy be delayed until calendar year 2013. Order Modifying the Poultry and Swine Waste Set-Aside Requirements and Granting Other Relief, NCUC Docket No. E-100, Sub 113, November 29, 2012.

[12] For more information about the OptimaBIOGAS model, see Appendices D–H.

implementation, it does not include certain costs, such as the internal rate of return required by one or more project developers or intermediaries to pursue projects and any payments to swine producers to secure biogas supplies. In addition, the analysis does not include costs to land apply or otherwise dispose of effluent from anaerobic digesters. Therefore, this modeling exercise is intended to present the relative basic costs associated with the four scenarios considered to comply with REPS targets and should be reviewed with the understanding that its LCOEs represent the best rough estimate of costs. Actual implementation costs may reflect other costs not discernible at this point. The LCOEs presented in this report should be used to compare scenarios, and the authors caution against relying on the absolute LCOE values as a final price for electricity. Additional study based on reasonable business model scenarios could further refine cost projections and develop more precise estimates of LCOEs, as discussed in Section 4.

Modeling Approach

The OptimaBIOGAS model examined, among other factors, the location, size, and density of swine operations in North Carolina; options for biogas production and transport and electricity production; and the potential for economies of scale to determine the optimal number and configuration of swine operations and energy production methods to fulfill each stage of the REPS and the total REPS mandate for four specific scenarios. These scenarios were based on methods currently available for generating energy from swine waste, all of which involve anaerobic digestion of the waste stream to produce biogas.[13] The scenarios are

- On-farm electricity production
- On-farm biogas collection and pipeline injection (individual farm-directed biogas)
- Centralized electricity production at a hub supplied by biogas from a high-density cluster of swine operations (centralized electricity production)
- Injection of biogas into the natural gas pipeline from a centralized gas pressurization and cleaning station supplied by biogas from a high-density cluster of swine operations (centralized directed biogas)[14]

Figure 3 shows these two electricity production and two biogas injection ("directed biogas") scenarios.

---

[13] Two other scenarios, involving transporting biogas generated at each farm to a central hub via trucks or transporting waste from multiple farms into a centralized anaerobic digester, were briefly considered. They were not included in the analysis after initial research indicated that overland transport of biogas and transport of waste would not be financially viable.

[14] Injection of conditioned methane into the natural gas pipeline to fuel natural gas-powered electricity-generating facilities is commonly referred to as "directed biogas." The NCUC ruled in March 2012 that directed biogas is a renewable energy resource that can be used to generate renewable energy certificates in compliance with North Carolina's REPS mandate. Order on Request for Declaratory Ruling, NCUC Docket No. SP-100, Sub 29, March 21, 2012. In North Carolina, biogas is being collected at landfills and at swine and dairy farms, but no project in the state is currently injecting biogas into the existing natural gas pipeline. For guidance for pipeline injection projects, see a report by the Gas Technology Institute, *Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane into Existing Natural Gas Networks*, available at http://www.gastechnology.org/market_results/Pages/Dairy-Waste-Biomethane-Interchangeability-Oct2009.aspx.

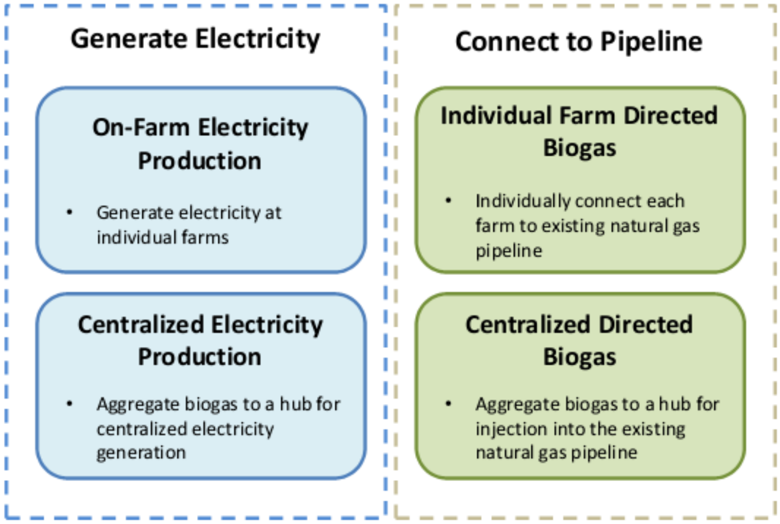


Figure 3. The four case study scenarios evaluated as part of the analysis.

Of the four scenarios, two include use of biogas to power electricity-generating equipment, either on individual farms or at a centralized hub. The other two involve the use of directed biogas, which was approved by the North Carolina Utilities Commission in March 2012 as a renewable energy source. Directed biogas allows utilities to receive credit in the form of renewable energy certificates (RECs) for electricity generated from purified and pressurized biogas that is injected into the pipeline system to power an upstream or downstream electric generation facility.[15] As was the case for the electricity generation-based scenarios, researchers applied the OptimaBIOGAS model to directed biogas scenarios to configure the optimal systems either for conditioning biogas at the individual farm level for direct injection into the existing natural gas pipeline network or for transporting biogas from individual farms to a centralized conditioning and injection hub through a newly constructed inter-farm network of low-pressure pipelines. Although pipeline injection involves many steps and stringent requirements (such as meeting specific pressure and purity levels and relying on an inter-farm pipeline infrastructure to transport gas from individual farms to a centralized hub and injection point), the model identified efficiency gains that could make pipeline development competitive. These gains could be realized through location of networks in high-density biogas production clusters and through increased power conversion efficiency at utility-sized plants.

In all cases, the OptimaBIOGAS model assumed that the fuel source will consist of biogas harvested through anaerobic digestion of swine waste, either by covering of existing waste lagoons or by construction of in-ground high-density polyethylene (HDPE)-lined and covered ambient temperature mixed digesters.[16] Researchers used the model to select the least-cost arrangement of equipment to process all the biogas generated at each farm in each scenario. For the scenarios involving piping of

[15] Order on Request for Declaratory Ruling, NCUC, Docket No. SP-100, SUB 29 (Mar. 21, 2012).
[16] Swine gas can be anaerobically digested in many ways, including with the use of proprietary digester technologies, with varying biogas production efficiencies. For the purposes of this analysis, researchers considered what they determined to be two of the most common approaches. Further analysis could consider other options, such as aboveground and heated digesters.

biogas between farms, OptimaBIOGAS produced the least-cost pipeline path between the farm and a centralized hub or existing natural gas pipeline.

To derive the total levelized cost of electricity (LCOE) for each scenario, the OptimaBIOGAS model included such considerations as the estimated costs to capture and harvest the biogas at each swine operation identified by the model (extrapolated from actual costs) and the estimated costs of injecting biogas into the natural gas pipeline or connecting electricity generation equipment to the power grid. Table 2 lists all costs included in the LCOE calculation for each scenario.[17]

Researchers also estimated station service, or the amount of electricity necessary to power the equipment required to generate the renewable electricity, and deducted it from the total amount of estimated electricity generation.[18] Because destruction of methane from livestock operations is an approved project type under the new California greenhouse gas trading system, the potential revenues from the sale of carbon offset credits were also estimated, using a carbon price of $10 per carbon credit, which is equivalent to the reduction of one metric ton of carbon dioxide equivalents.[19]

Table 2. Capital and operating costs included in LCOE calculation, by scenario

	On-Farm Electricity Production	On-Farm Directed Biogas	Centralized Electricity Production	Centralized Directed Biogas
Biogas Collection Costs	Biogas harvesting and capture	Biogas harvesting and capture	Biogas harvesting and capture	Biogas harvesting and capture
Biogas Conditioning Costs	On-farm biogas conditioning equipment	On-farm biogas conditioning equipment	On-farm biogas conditioning equipment	On-farm biogas conditioning equipment
Biogas Compression Costs		On-farm compressor		Centralized biogas conditioning equipment and compressor

[17] In the calculation of LCOE, researchers divided costs into distinct components, as shown in Table 2; specific costs for those components are listed in Appendix B. The cost components involving equipment selection were optimized using the OptimaBIOGAS model. Other costs, including biogas collection costs and interconnection costs, were calculated separately; assumptions about these costs can be changed quickly without the need to re-run the entire model.

[18] Station service is defined as "the portion of electricity or thermal energy produced by a Renewable Energy Facility that is immediately consumed at that same facility in order to power the facility's pumps, etc., or to process fuel." NCUC Docket No. E-100, Sub 121 (July 1, 2010). In North Carolina, station service is not eligible to earn RECs. In this analysis, on-farm electricity production appears to be affected slightly more by the station service requirements because it would establish hundreds of new generation facilities, each with a small station service load from generation and data collection equipment. The other scenarios use far fewer and more efficient facilities, plus would have fewer components to count as station service and hence would result in less overall station service.

[19] The carbon credits generated by these projects would be eligible for sale in the California carbon market, in which allowances currently trade at approximately $10 per metric ton of carbon dioxide equivalent ($MTCO_2e$). Allowance prices serve as a good proxy for offset prices. The carbon revenues calculated for these projects take into account the costs of monitoring and third-party verification. See Appendix C for more information on the calculation of revenue from carbon credits.

Biogas Transport Costs		High-pressure pipeline and right of way between farms and natural gas pipeline	Low-pressure pipeline and right of way between farms and centralized hub	Low-pressure pipeline and right of way between farms and centralized hub
				High-pressure pipeline and right of way between centralized hub and natural gas pipeline
Electricity Generation Costs	On-farm electricity generation equipment		Centralized electricity generation equipment	
Interconnection Costs	Interconnection to the electric power Grid	Interconnection to the natural gas Pipeline	Interconnection to the electric power Grid	Interconnection to the natural gas Pipeline

As mentioned previously, in all cases, the model assumes that biogas is collected at each farm through the process of anaerobic digestion.[20] Researchers evaluated each configuration or scenario for each stage of the REPS (i.e., 2013, 2015, and 2018 and beyond) on the basis of the scenario's LCOE on a per-kilowatt-hour basis. For the lowest-cost scenarios, they compared biogas production options, including covering the farms' existing swine waste lagoons or installing in-ground lined-and-covered mixed anaerobic digesters. This comparison indicates that mixed anaerobic digesters reduce overall costs because they can be less expensive to install than lagoon covers depending on the size of the existing lagoon and because they increase gas output on a per-farm basis, thereby decreasing the overall number of farms that must participate to meet the REPS requirements.

With respect to the two lowest-cost scenarios identified by the model, the analysis also examines the cost to install innovative animal waste management systems, which can improve the environmental performance of swine waste management with respect to a number of environmental, public health, and nuisance issues, including odors, discharge of waste to surface and groundwater, and emissions of ammonia, nutrients, pathogens, and heavy metals. Although economic benefits associated with improved environmental performance have been documented at a large scale, the analysis did not include farm-by-farm economic benefits, including increased revenue from increased farm size and the potential to decrease mortalities, improve feed conversion, and convert low-value sprayfield crops to higher-value cash crops. Evaluation of revenue streams from such benefits is recommended.

[20] The model's choices for anaerobic digestion were limited to covered lagoons and in-ground mixed digesters similar to the digester constructed at the Loyd Ray Farms site in Yadkin County, North Carolina. Modelers chose anaerobic digestion and these two specific methods of anaerobic digestion because of the likelihood of interest in anaerobic digestion as a basis for waste-to-energy projects and because of their familiarity with and access to pricing data for covered lagoons and in-ground mixed anaerobic digesters.

Description of Scenarios

The OptimaBIOGAS model allowed researchers to evaluate and optimize four scenarios for generating electricity from swine waste. The modeling approach generally contemplates use of one scenario to meet the requirements of a single stage of the REPS, but there is no limit or prescribed sequencing for deploying swine WTE. Although a centralized approach may be the most cost-effective in the long term, developers may wish to begin to deploy projects on an individual farm basis for on-farm electricity production and then link individual farms to a centralized system as technology and energy production are refined or pursue some on-farm production until an inter-farm biogas pipeline can be established, thereby combining aspects of both centralized and on-farm production at each stage of the REPS.

The analysis employs OptimaBIOGAS to configure various arrangements under the four scenarios. Although each scenario has particular benefits and drawbacks, the model focuses only on electricity production costs, including capital and operating costs, associated with fulfilling the REPS swine set-aside per the process prescribed in the specific scenario.[21] Note that all costs are projected at a maximum project length of twenty years.

On-Farm Electricity Production Scenario: With respect to on-farm electricity production (Scenario 1), the model assumes that biogas will be collected on individual swine farms, "lightly conditioned" (i.e., dehumidified and compressed to a relatively low pressure compared with the pressure required for injection into the natural gas pipeline network), and used to generate electricity on site, for transmission to the power grid. The design and operation of the WTE process occurs entirely on the participating farms and assumes the use of a gas conditioning unit, an electricity-generating device, and the electrical infrastructure to connect the power device to the grid, as illustrated in Figure .

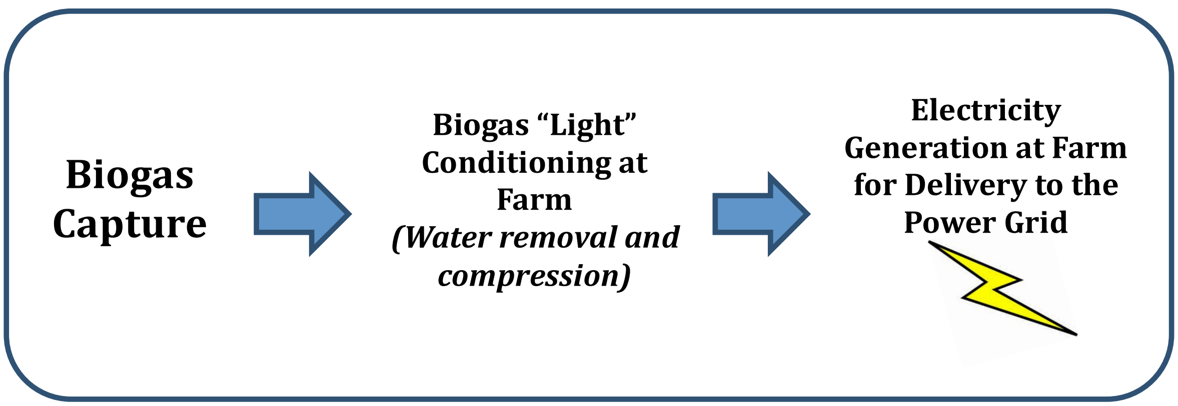


Figure 4. Design and operation of the WTE process in the on-farm electricity production scenario (Scenario 1).

[21] Because few swine WTE projects have been implemented thus far in North Carolina, researchers chose to apply conservative estimates for operating costs and to employ conservative assumptions regarding the types, capabilities and maintenance needs of the equipment included in the analysis. For example, rather than modeling increased maintenance of equipment that generates electricity in order for it to process high-humidity and other impurities in the biogas, researchers chose to include biogas conditioning equipment that would dehumidify the biogas and remove hydrogen sulfide and other impurities to protect the equipment that received the biogas, such as internal combustion engines. Applying conservative assumptions related to equipment needs and performance had the effect of increasing equipment costs.

Figure 5 shows the on-farm equipment and potential system configuration for on-farm electricity production.

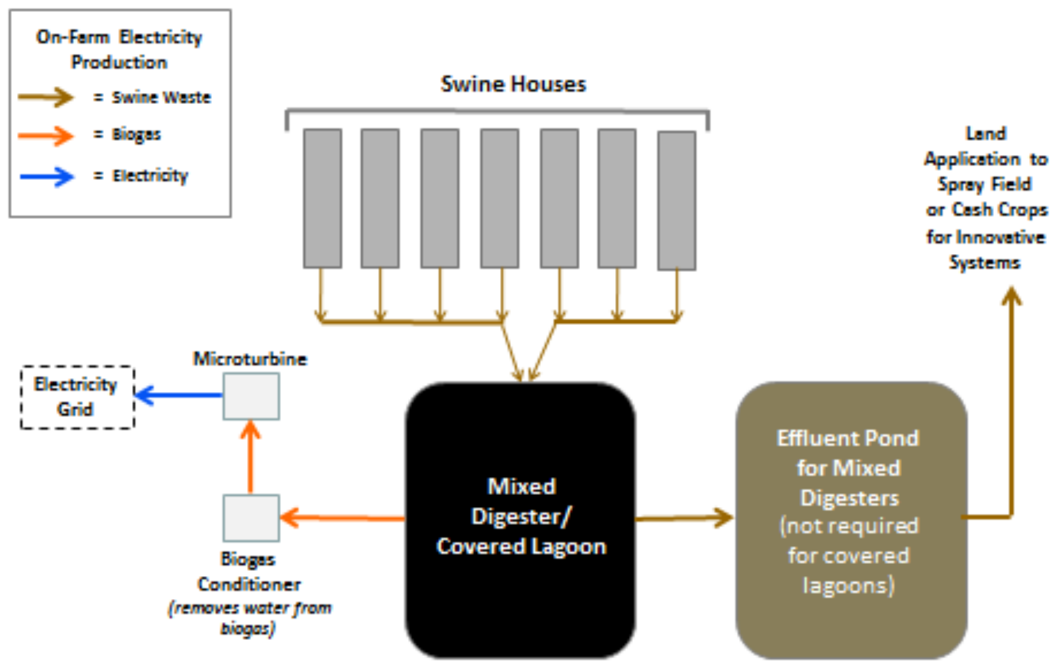


Figure 5. Flow diagram of on-farm electricity production (Scenario 1).

Note: Mixed digesters or covered lagoons could be used to capture the biogas. Mixed digesters would necessitate a separate basin, such as the farm's existing lagoon, for effluent storage; covered lagoons would not require a separate basin.

Table 3 describes all the components available to the model in identifying the optimal system configuration at each farm as well as the cost components reflected in the LCOE calculation for the on-farm electricity production scenario. More specific information related to equipment options, including manufacturers, capacities, and estimated costs, can be found in Appendix A.

Table 3. Components considered for on-farm electricity production and on-farm electricity production as part of an innovative animal waste management system

	On-Farm Electricity Production (Scenario 1) Cost Components
Biogas Collection Costs	Biogas harvesting and capture costs include the cost of either covering the existing swine waste lagoon with 60-mill HDPE or installing a new in-ground lined and covered (with 60-mill HDPE) mixed anaerobic digester at each farm. The costs for the mixed digester include mixing pumps and baffles for flow disruption to improve the biogas output from the digester. Digesters can be sized by many different methods; the method used by the OptimaBIOGAS model was based on information from the USDA Natural Resources Conservation Service. The cost of any particular project may differ based on the method chosen.
Biogas Conditioning Costs	Biogas conditioning equipment in Scenario 1 is located on each farm, and the costs include installing and operating either a "light conditioner," which removes water and particulates from the biogas before sending it to a microturbine, or a "heavy conditioner," which also removes hydrogen sulfide from the gas before sending it to an internal combustion engine generator.
Electricity Generation Costs	Electricity generation equipment in Scenario 1 is located on each farm, and the costs include installing and operating either a microturbine or an internal combustion engine generator to generate electricity on each farm.
Interconnection Costs	Interconnection costs include the costs to connect each microturbine or generator at each farm to the electric power grid. Interconnections were assumed to handle three-phase power. Interconnection costs were based on general averages and could be improved by undertaking more analysis of each farm.
Innovative Animal Waste Management System Components	For Scenario 1, the analysis also examines the cost of installing additional components that would qualify the WTE system as an innovative animal waste management systems to meet the state environmental performance standards. Innovative system components evaluated in the study include the installation of a separate lined in-ground basin with jet aeration equipment to aerate the digester effluent to reduce the concentration of ammonia, odors, and pathogens.

On-Farm Directed Biogas Scenario: Like Scenario 1, the on-farm directed biogas scenario (Scenario 2) involves neither centralization of the biogas stream nor economies of scale. Biogas is collected on individual farms but is not used to generate electricity on-site. Instead, it is purified to pipeline specifications (through carbon dioxide and hydrogen sulfide removal) and pressurized to at least 800 pound-force per square inch or psi[22] ("heavy conditioning"), and injected into high-pressure pipelines running directly between the farm and the natural gas transport pipeline network.[23] Via this network, the biogas is assumed to travel to an existing natural gas combined-cycle utility plant for electricity generation, as depicted in Figure 6.

[22] The biogas is assumed to be injected into high-pressure transport pipelines rather than low-pressure distribution pipelines.
[23] Biogas is injected into high-pressure transport pipelines. Injection into high-pressure pipelines allows the purified and pressurized biogas to mix with the high quantity of natural gas in the high-pressure pipeline, which also avoids any possibility that gas quality issues could arise from biogas injection into lower-pressure consumer service pipelines.

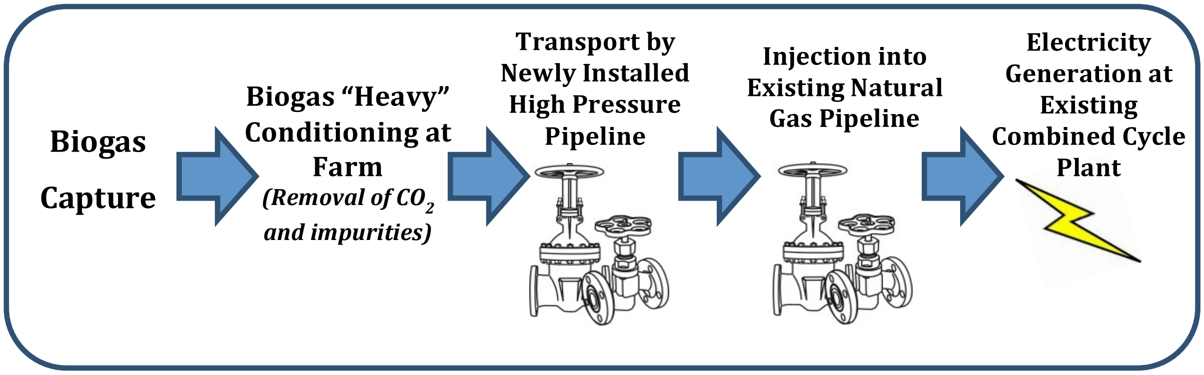


Figure 6. Design and operation of the WTE process in Scenario 2.

Figure 7 illustrates the on-farm equipment and potential system configuration for on-farm directed biogas.

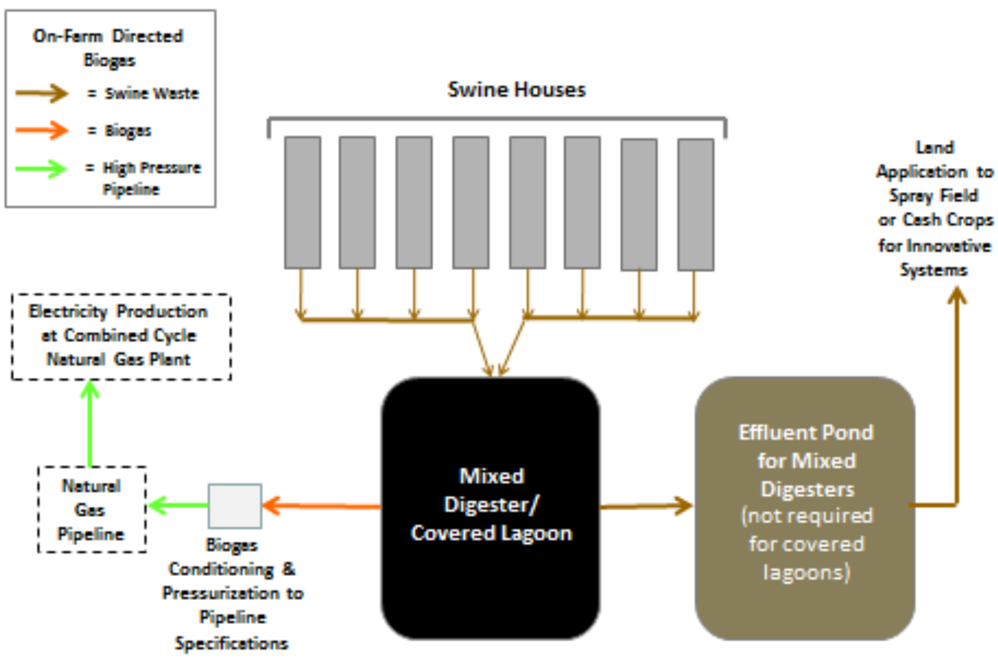


Figure 7. Flow diagram of on-farm directed biogas (Scenario 2).

Note: Mixed digesters or covered lagoons could be used to capture the biogas. Mixed digesters would necessitate a separate basin, such as the farm's existing lagoon, for effluent storage; covered lagoons would not require a separate basin.

Table 4 describes all the components available to the model in identifying the optimal system configuration at each farm as well as the cost components reflected in the LCOE calculation for the on-farm directed biogas scenario. More specific information related to equipment options, including manufacturers, capacities, and estimated costs, can be found in Appendix A.

Table 4. Cost components used to calculate the levelized cost of electricity for on-farm directed biogas

	On-Farm Directed Biogas (Scenario 2) Cost Components
Biogas Collection Costs	Biogas harvesting and capture costs include the cost of either covering the existing swine waste lagoon with 60-mill HDPE or installing a new in-ground lined and covered (with 60-mill HDPE) mixed anaerobic digester at each farm. The costs for the mixed digester include mixing pumps and baffles for flow disruption to improve the biogas output of the digester. Digesters can be sized by many different methods; the method used here was based on information from the USDA Natural Resources Conservation Service. The cost of any particular project may differ based on the method chosen.
Biogas Conditioning Costs	Biogas conditioning and compression equipment in Scenario 2 would be located on each farm, and the costs include installing and operating a "heavy conditioner," which removes carbon dioxide and hydrogen sulfide from the biogas before sending it to a two-stage compressor. The compressed biogas is then injected into the high-pressure natural gas pipeline.
Biogas Transportation Costs	The compressed biogas is transported to the natural gas pipeline via a high-pressure pipeline that would connect each farm to the high-pressure pipeline. The costs include the capital and operating costs of installing new high-pressure pipeline and acquiring and maintaining right of way between farms and the existing natural gas pipeline. Pipeline costs were obtained from industry sources and were presented and evaluated in terms of a high-cost estimate and a low-cost estimate. The estimates represent an annual cost of service over a 15-year period and include capital and operating costs and a rate of return for the gas utility or pipeline operator.
Interconnection Costs	Interconnection costs include the cost of injecting the conditioned biogas into the high-pressure natural gas pipeline. These costs were obtained from industry sources and were presented and evaluated in terms of a high cost estimate and a low cost estimate.

Centralized Electricity Production Scenario: In the centralized electricity production scenario (Scenario 3), biogas is collected on individual farms, but the biogas stream is dehumidified on site. The "lightly conditioned" biogas is then transported by an inter-farm pipeline to a centralized hub. The hub then aggregates all the biogas from participating farms, conditions the biogas, and generates electricity on a larger scale than would occur at individual farm operations. The system will be feasible only if the efficiency gains from economies of scale can offset the additional costs to transport the gas through a network of pipelines to a centralized hub. Figure 8 represents the process flow for Scenario 3.

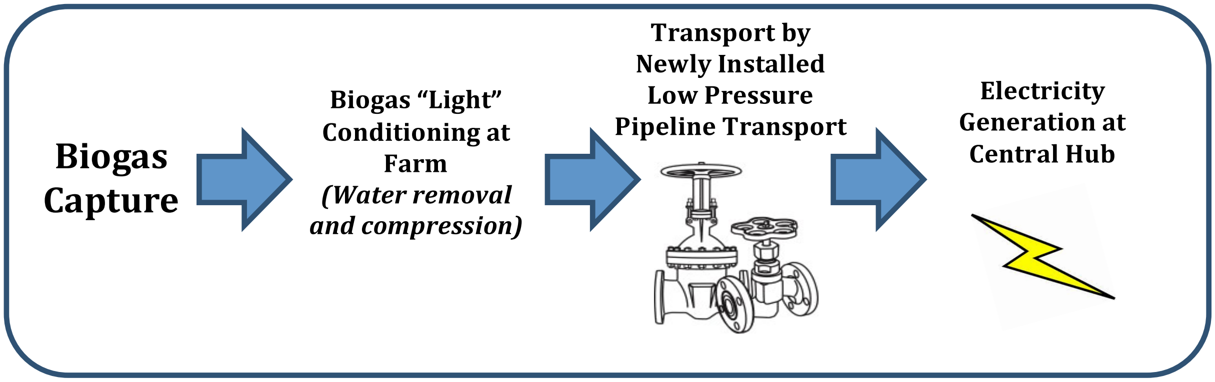


Figure 8. Design and operation of the WTE process in the centralized electricity production scenario (Scenario 3).

From a farm perspective, centralized electricity production would likely be configured as shown in Figure 9.

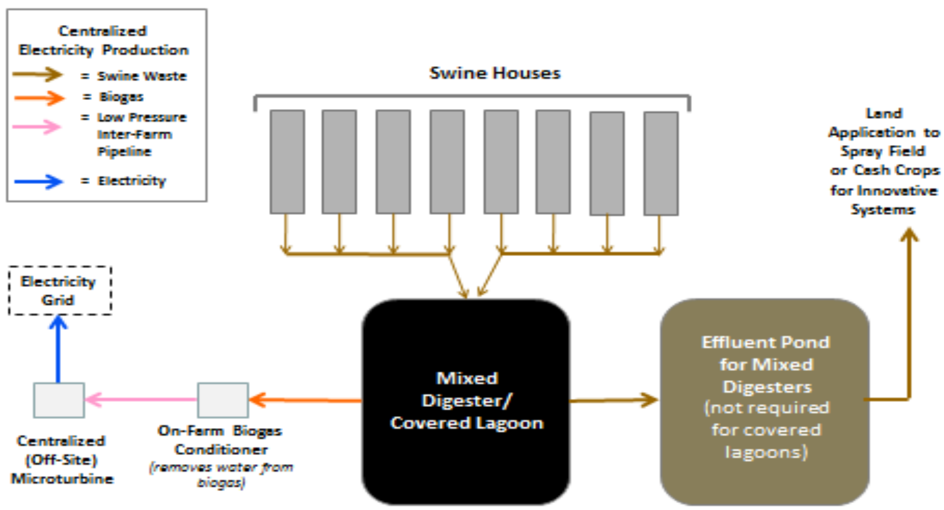


Figure 9. Flow diagram of centralized electricity production (Scenario 3).

Note: A mixed digester or covered lagoon could be used to capture the biogas. A mixed digester would require a separate basin, such as the farm's existing lagoon, for effluent storage. Lagoons would not require a separate basin.

Table 5 describes the specific pieces of equipment available to the model in identifying an optimal configuration as well as the cost components reflected in the LCOE calculation for the centralized electricity production scenario. More specific information related to equipment options, including manufacturers, capacities, and estimated costs, can be found in Appendix A.

Table 5. Cost components used to calculate the levelized cost of electricity for the centralized electricity production scenario

	Centralized Electricity Production (Scenario 3) Cost Components
Biogas Collection Costs	Biogas harvesting and capture costs include the cost of either covering the existing swine waste lagoon with 60-mill HDPE or installing a new in-ground lined and covered (with 60-mill HDPE) mixed anaerobic digester at each farm. The costs for the mixed digester include mixing pumps and baffles for flow disruption to improve the biogas output of the digester. Digesters can be sized with a variety of methods; the method employed by the instant analysis was based on information from the USDA Natural Resources Conservation Service. The cost of any particular project may differ based on the method chosen.
Biogas Conditioning Costs	Biogas conditioning equipment in Scenario 3 is located on each farm, and the costs include installing and operating a "light conditioner," which removes water and particulates from the biogas before sending it to a low-pressure inter-farm pipeline network.
Biogas Transport Costs	After the biogas is conditioned, it is sent through a low-pressure pipeline network to a central hub. The costs include the capital and operating costs of installing new low-pressure pipeline and acquiring and maintaining right of way between farms and the central hub. Pipeline costs were obtained from industry sources and were presented and evaluated in terms of a high-cost estimate and a low-cost estimate. The estimates represent an annual cost of service over a 15-year period and include capital and operating costs and a rate of return for the gas utility or pipeline operator.
Electricity Generation Costs	Electricity generation equipment in Scenario 3 is located at centralized hubs, and the costs include the cost of installing and operating either a microturbine or an internal combustion engine generator to generate electricity on each farm. Economies of scale were not found in this analysis for electricity generation of the aggregated biogas.
Interconnection Costs	Interconnection costs include the costs to connect the microturbines and/or generators at the central hubs to the electric power grid. Interconnections were assumed to handle 3-phase power. Interconnection costs were based on averages, which could be improved by determining interconnection costs for each specific farm.

Centralized Directed Biogas Scenario: The centralized directed biogas scenario (Scenario 4) is like Scenario 2 but adds a network of pipelines to transport the gas between individual farms to a centralized hub or hubs. In Scenario 4, biogas will be collected at the farm, lightly conditioned, and injected into low-pressure pipelines for transport to a local hub. The hub will aggregate all the biogas from participating farms, perform additional purification to ensure the biogas meets pipeline standards, compress the biogas, and inject it into a single high-pressure pipeline that will connect the hub to the national natural gas pipeline network for use upstream or downstream from the injection point. Although this system may be the most complex of the four scenarios (see Figure 10), the overall costs could be the lowest because of vast efficiency gains, especially when the gas is used to power an existing high-efficiency utility-size generator.[24] Because the centralized directed biogas scenario, like the on-farm directed biogas scenario, assumes that an existing generation unit will be used, no additional costs for electricity generation are included.

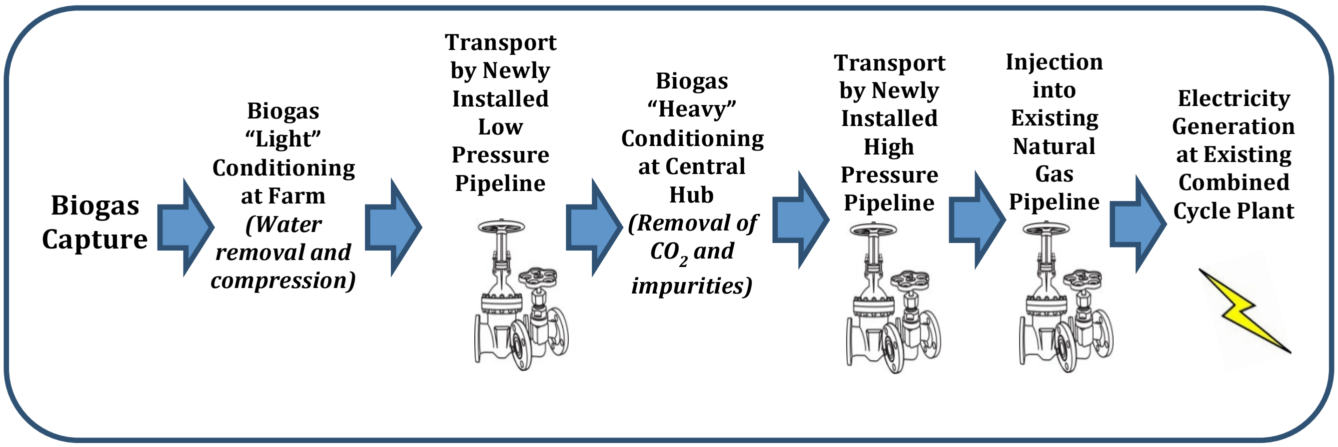


Figure 10. Design and operation of the WTE process in the centralized directed biogas approach (Scenario 4).

[24] The analysis used a heat exchange rate of 7.2 MMBtu/MWh of electricity generated. The heat exchange rate of a microturbine is approximately 10.3 MMBtu/MWh. For more information, see the discussion on identifying and grouping farms to fulfill REPS requirements.

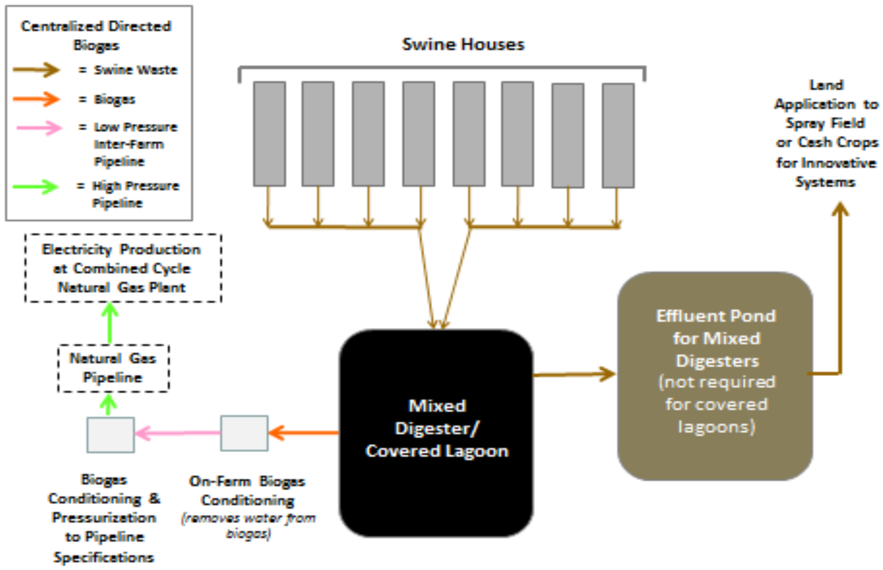


Figure 11. Flow diagram of centralized directed biogas (Scenario 4).

Note: Mixed digesters or covered lagoons can be used to capture the biogas. Mixed digesters would necessitate a separate basin, such as the farm's existing lagoon, for effluent storage. Covered lagoons do not require a separate basin.

Table 6 provides an overview of the specific pieces of equipment available to the model in identifying an optimal configuration for each cost component and the system overall. More specific information regarding equipment options, including manufacturers, capacities, and estimated costs, can be found in Appendix A. Table 6 also includes the add-on components used to determine additional costs on a per-kilowatt-hour basis for installing a complete innovative animal waste management system for centralized directed biogas. The components and their costs were based on the system installed at the Yadkin County operation and were applied on a per-head basis.

Table 6. Cost components used to calculate the levelized cost of electricity for the centralized directed biogas scenario plus costs of additional components to qualify as an innovative animal waste management system

	Centralized Directed Biogas (Scenario 4) Cost Components
Biogas Collection Costs	Biogas harvesting and capture costs include the cost of either covering the existing hog waste lagoon with 60-mill HDPE or installing a new in-ground lined and covered (with 60-mill HDPE) mixed anaerobic digester at each farm. The costs for the mixed digester include mixing pumps and baffles for flow disruption to improve the biogas output of the digester. Digesters can be sized with many methods; the method used here was based on information from the USDA Natural Resources Conservation Service. The cost of any particular project may differ based on the method chosen. The analysis also examines the cost of installing innovative systems to control environmental pollutants from the swine waste. Innovative systems include jet aeration equipment in the digester effluent pond to aerate the wastewater to reduce the concentration of ammonia, odors, and pathogens.
Biogas Conditioning and Compression Costs	Biogas conditioning equipment in Scenario 4 is located both at each farm and in a centralized hub. The on-farm equipment includes a "light conditioner," which removes water and particulates from the biogas before sending it to the low-pressure pipeline network. The centralized equipment includes a "heavy conditioner," which removes carbon dioxide and hydrogen sulfide from the gas before sending it to a two-stage compressor. The compressed biogas is then sent to a high-pressure pipeline. The biogas conditioning costs include the costs to install and operate both the on-farm and centralized biogas conditioning equipment as well as the costs of the two-stage compressor necessary to compress the gas to pipeline specifications.
Biogas Transport Costs	Scenario 4 includes both low-pressure and high-pressure pipelines. Individual farms are connected to a centralized hub via a low-pressure pipeline network. After gas is conditioned and compressed at the hub, it is sent to the existing natural gas pipeline network via high-pressure pipelines. The costs include the capital and operating costs of installing new low- and high-pressure pipeline and acquiring and maintaining right of way between farms and the central hub and between the hub and the natural gas pipeline. Pipeline costs were obtained from industry sources and were presented as a range.
Interconnection Costs	Interconnection costs include the cost of injecting the conditioned biogas into the natural gas pipeline. These costs were obtained from industry sources and were presented as a range.
Innovative Animal Waste Management System Components	As with Scenario 1, the analysis also examines the cost of installing additional components that would qualify the WTE system as an innovative animal waste management system in compliance with the state environmental performance standards. Innovative system components evaluated in the study include the installation of a separate lined in-ground basin with jet aeration equipment to aerate the digester effluent to reduce the concentration of ammonia, odors, and pathogens.

Model Design

OptimaBIOGAS consists of a series of optimization models that perform spatial and economic optimizations in an iterative fashion. Researchers established individual optimization modeling steps specifically for each scenario, and the grouping or groupings of swine operations for each scenario were iteratively determined according to the assumption of each scenario as well as the biogas production capacities of the swine operations, the distance between swine operations, and spatial obstacles (e.g., waterways or protected areas) of biogas pipeline construction. The configuration of the farms is a crucial step in the analysis and allows for LCOE determinations. Once the LCOEs of all scenarios were calculated, the scenarios could be compared.

Among the major challenges of modeling an optimal swine-based biogas electric power-generating system in North Carolina is the large number of swine operations to consider as well as the complexity of the analysis. The farm selection process is described and the iterative modeling process is explained below.[25]

Farm and Hub Selection

Regarding farm selection, OptimaBIOGAS narrowed the location of farms and groupings by identifying North Carolina's highest-yielding biogas operations (based on farm type and number of animals) and the density of swine farms. The location of individual farms and the configuration of the low-pressure inter-farm pipeline necessary to fulfill the directed biogas scenario for stage 1 of the REPS are shown below for biogas capture in covered lagoons (Figure 12) and in mixed digesters (Figure 13). If mixed digesters are employed, only 39 farms in a comparatively small spatial area are needed to comply with stage 1 of the REPS, compared with 86 farms if covered lagoons are employed. Additional maps for stages 2 and 3 are found in Appendix A. To optimize efficiency by maximizing biogas production within the smallest area, thereby reducing pipeline length, participating farms would be limited to those located in Duplin and Sampson counties in stage 1. The same farms would be chosen for Scenario 1 (individual-farm electricity production) because they are also the farms with the highest biogas output in the state.

[25] The researchers attempted to reduce modeling complexity with respect to the number of farms by limiting the analysis to farms capable of producing 7,500 or less MMBtu/year of biogas. Even after applying this threshold, researchers had many more farms than necessaryfor full comply with the REPS requirements.

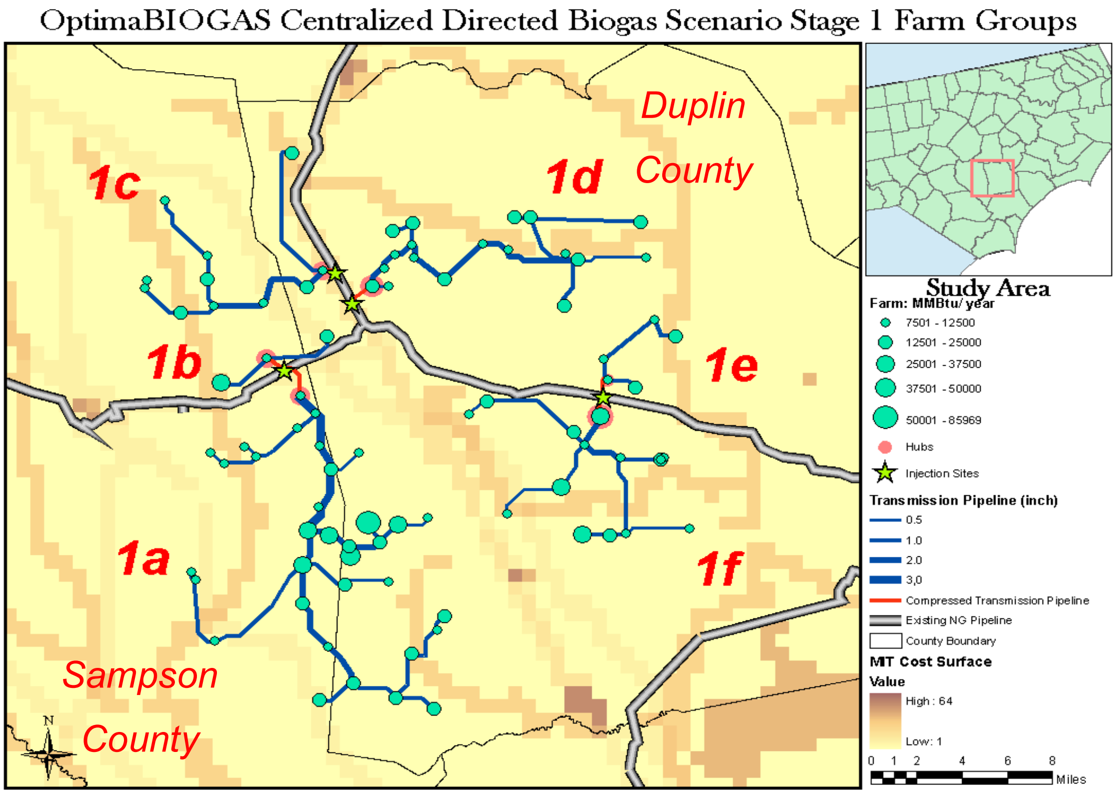


Figure 12. Individual farms, farm clusters, pipeline configurations, and hubs necessary to fulfill the centralized directed biogas scenario for stage 1 of the REPS, assuming use of covered lagoons for biogas capture. The subgroups (i.e., 1a, 1b, and so on) are groupings of farms, and each subgroup would have a single point of injection to the existing natural gas pipeline, as shown by the stars in the figure.

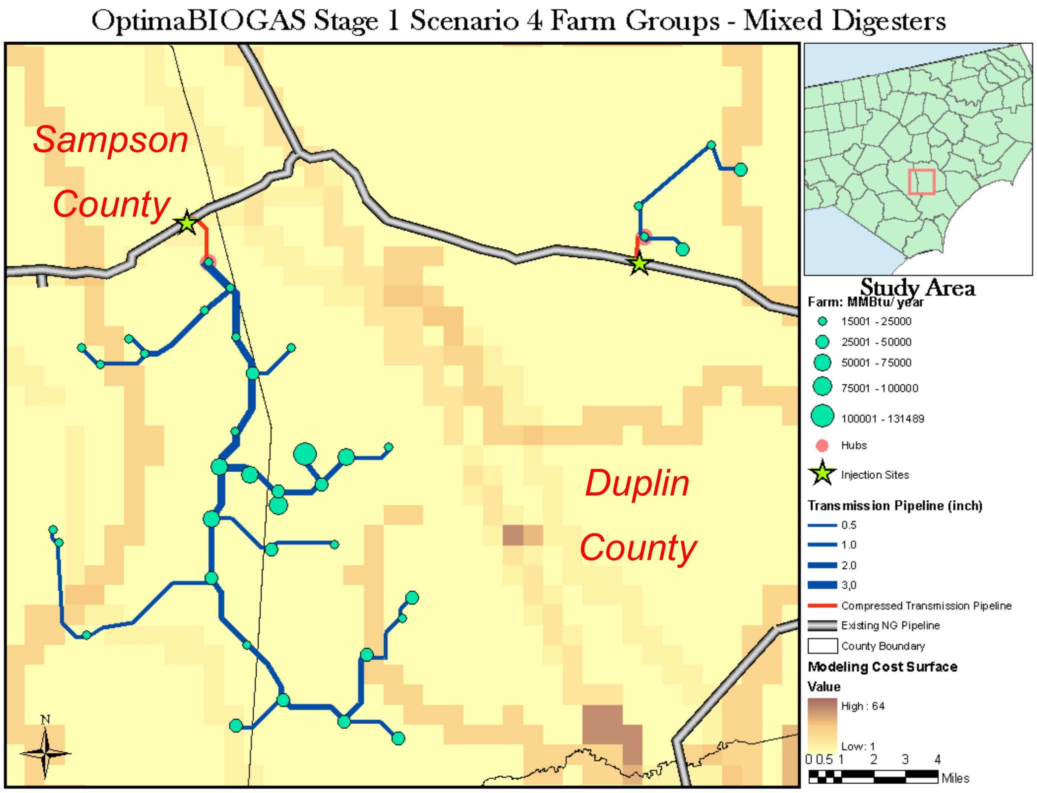


Figure 13. Individual farms, farm clusters, pipeline configurations, and hubs necessary to fulfill the centralized directed biogas scenario for stage 1 of the REPS, assuming use of covered lagoons for biogas capture.

To be clear, the OptimaBIOGAS model determines the LCOE for the four scenarios on the basis of a single configuration of farms identified at the outset of the analysis (see the farm and hub selection discussion, below). To select the farms that would be included in the biogas system—be it an on-farm production or centralized system—modelers first identified the biogas potential for each farm in North Carolina. Figure 2 illustrates the biogas potential of all North Carolina swine operations. The amount of biogas that can be produced is determined by the type of farm (e.g., feeder-to-finish, sow operation) and the number of animals on each farm.

The total biogas production rate for each farm can be calculated from the potential volume of biogas in million British thermal units (MMBtu) that can be captured on an annual basis. Methane generation data for each type of swine farm was converted to the energy content generated on a per-head and per-steady-state-live-weight (SSLW) basis, detailed in Table 7. Because biogas production can vary considerably across farms and within farm types, the average represents a wide range.

Table 7. Biogas production rate for farm types based on the use of covered lagoons or mixed digesters. An explanation of the farm types is listed in Appendix A, section A.9. The farm types listed and SSLWs used in the calculations correspond to the permitting categories for North Carolina swine farms.

Farm Type	Covered Lagoons				Mixed Digesters			
	Per Nominal Head		Per 1,000 lbs. SSLW		Per Nominal Head		Per 1,000 lbs. SSLW	
	Methane (CH_4) Generated	Btu Generated	Methane (CH_4) Generated	Btu Generated	Methane (CH_4) Generated	Btu Generated	Methane (CH_4) Generated	Btu Generated
	ft3/yr.	*MMBtu/yr.*	*ft3/yr.*	*MMBtu/yr.*	*ft3/yr.*	*MMBtu/yr.*	*ft3/yr.*	*MMBtu/yr.*
Boar Stud	1,150	0.665	2,875	1.66	2,300	1.33	5,750	3.33
Farrow-to-Wean	1,183	0.685	2,731	1.58	2,365	1.37	5,462	3.16
Farrow-to-Feeder	1,603	0.93	3,070	1.78	3,205	1.86	6,140	3.56
Farrow-to-Finish	18,422	10.65	13,000	7.52	36,843	21.3	26,001	15.03
Feeder-to-Finish	2,336	1.355	17,304	10.04	4,672	2.71	34,607	20.07
Wean-to-Feeder	420	0.25	14,000	8.33	840	0.5	28,000	16.67
Wean-to-Finish	2,068	1.2	17,978	10.43	4,135	2.4	35,957	20.87
Gilts	2,336	1.355	17,304	10.04	4,672	2.71	34,607	20.07

Compiled by: William Simmons, P.E., Cavanaugh and Associates P.A. *Sources:* American Society of Agricultural Engineers, 1992, Manure Production and Characteristics, ASAE Standard D384.1; American Society of Agricultural Engineers, 2005, Manure Production and Characteristics, ASAE Standard D384.2; USDA Natural Resources Conservation Service, 2009, *Agricultural Waste Management Field Handbook;* North Carolina State University, 2005, *Economic Assessments of Alternative Swine Waste Management Systems;* North Carolina State University, 2005, *Technology Report: Barham Farm.*

Identifying and Grouping Farms to Fulfill the REPS Requirements

After determining the total biogas production rate (MMBtu/year) for each farm, researchers identified biogas "hotspot" regions to reduce the potential pipeline costs for biogas transportation and to maximize the possibility of harnessing economies of scale. To ensure that the model selected enough farms to provide sufficient biogas to fulfill the REPS requirements in each scenario, the researchers assumed that a relatively high (and hence conservative) heat exchange rate of 14 MMBtu was required for every megawatt-hour of electricity produced (24% efficiency). Consequently, approximately 1,270,000 MMBtu per year would be required to comply with each stage of the REPS. However, each scenario has different electricity generation options, ranging from highly efficient combined-cycle natural gas power plants, with a heat exchange rate of 7.2 MMBtu per MWh (47% efficiency), to less efficient, smaller-capacity microturbines, with a heat exchange rate of 10.3 MMBtu per MWh (32% efficiency). Therefore, in some cases, the model selected more farms than would be necessary to comply with the REPS requirements in certain scenarios.

Next, the modeling team identified the areas in North Carolina with high biogas production rates using the "focal statistics" function in ArcGIS (Figure 14). The modeling team then calculated the total biogas production rate in MMBtu/year by 20-kilometer-diameter circular increments—or hotspots—across the entire state. The areas are ranked according to their total projected MMBtu production rate (Figure 15).

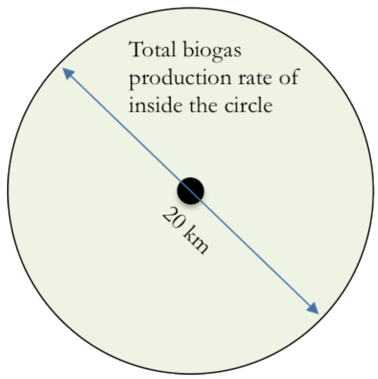


Figure 14. Illustration of focal statistics functionality.

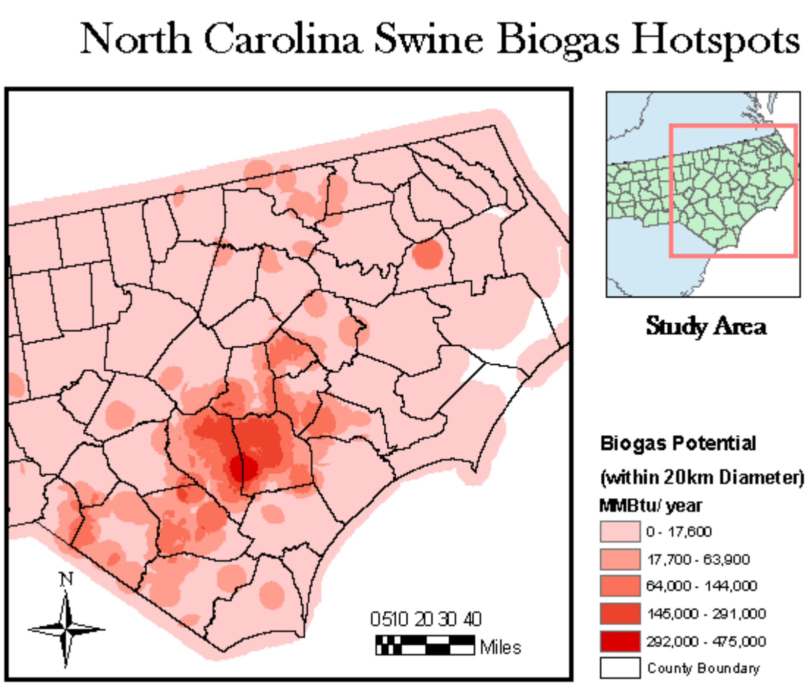


Figure 15. Twenty-kilometer-diameter biogas hotspots in North Carolina.

The potential farms were selected from high to low biogas hotspots to generate at least 1,270,000 MMBtu in order to meet the requirements for each stage of the REPS. Table 8 lists the number of farms selected to fulfill each stage of the REPS. As illustrated by Figure 16, the highest density of biogas hotspots are located in the Eastern Coastal Plain; the highest concentration of biogas production potential is in Duplin and Sampson counties.

Table 8. Amount of biogas production potential (MMBtu/year) identified by stage of REPS, based on biogas capture by covered lagoons or mixed digesters

REPS Stage	Year	Covered Lagoons		Mixed Digesters	
		Number of Farms	Biogas Potential (MMBtu/Year)	Number of Farms	Biogas Potential (MMBtu/Year)
Stage 1	2013	86	1,275,949	39	1,254,643
Stage 2	2015	107	1,270,708	46	1,240,104
Stage 3	2018	91	1,271,911	42	1,267,842
Total		284	3,818,568	127	3,762,589

Figure 16 illustrates the groups and spatial arrangement of farms identified by the model to meet each stage of the REPS. This spatial representation indicates the optimal farms to be deployed at each stage.

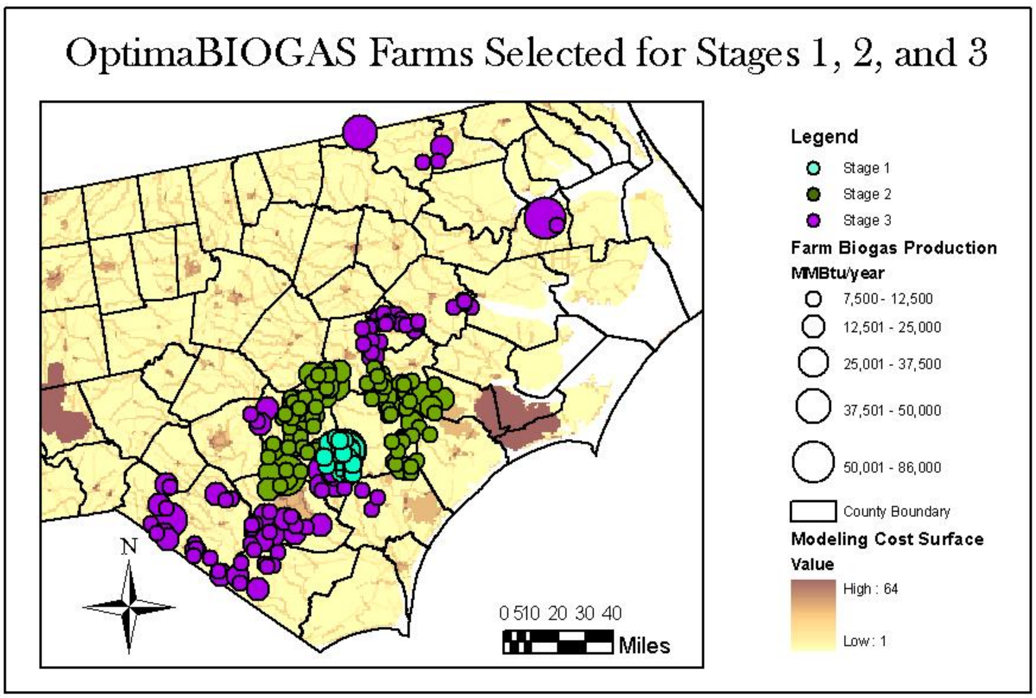


Figure 16. Farm groupings, by REPS stage.

Explanation of the Modeling Process

Using the centralized electricity production scenario as an example, Figure 17 illustrates the steps necessary to discern the LCOE, which starts with identification of the individual farms that should be included in the design of the system. Each diamond represents an optimization, and each square is the output of that modeling. At the farm level, biogas output is dependent on farm size and type.

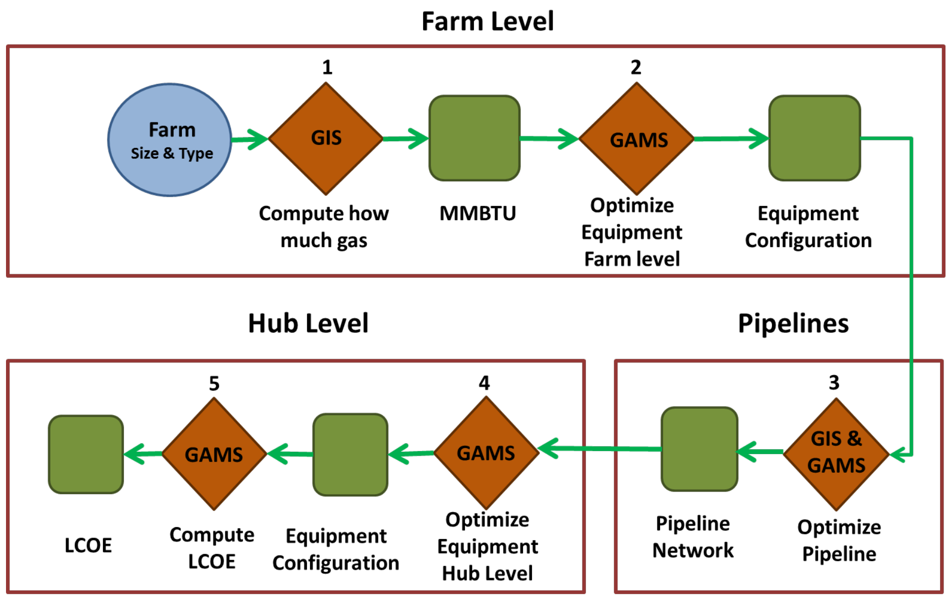


Figure 17. Overview of steps undertaken to implement an OptimaBIOGAS modeling run.

Again, using the centralized electricity production scenario as an example, the modeling process proceeds as follows:

1. Biogas production rates are estimated for each swine farm.

2. The equipment at the farm level is optimized for biogas production rates (i.e., the model chooses the least-cost arrangement of equipment that can process all the gas that is produced). The model outputs the optimal farm-level configuration of biogas conditioning equipment, which will dehumidify the biogas before it is piped into the local biogas pipeline network.

3. Biogas from farm cluster areas are aggregated and transported via low-pressure pipelines to a local hub. OptimaBIOGAS produces an optimal, least-cost pipeline configuration.

4. At the hub level, the biogas is either combusted by a turbine or undergoes "heavy" conditioning, whereby carbon dioxide, hydrogen sulfide, and other impurities are reduced, for injection into the pipeline. In the electricity generation stage, the biogas is burned in a combustion engine. As for on-farm equipment, the model optimizes the configuration of the conditioning and generation units.

5. Finally, the LCOE is calculated by dividing the total costs, including capital and operating costs, by the total amount of electricity generated over a 10- or 20-year period. For the purposes of this report, costs are reflected on the basis of a 20-year period.

Data Inputs

Data inputs for the modeling analysis were acquired on the basis of equipment known to be available to accomplish each scenario as well as information gleaned from the Loyd Ray Farms swine waste-to-energy project located in Yadkin County, North Carolina. The project is sponsored by Duke University, Duke Energy, and Google, Inc., and has received funding from the U.S.D.A. Natural Resources Conservation Service and the North Carolina Division of Soil and Water Conservation.[26] Data were also acquired on the basis of surveys of other livestock WTE projects, swine and otherwise, and from project developers and equipment providers in the biogas WTE field. The costs to transfer electricity generated at individual swine operations to the electricity grid were added to the LCOEs for the on-farm electricity production and centralized electricity production scenarios; biogas pipeline construction and transport costs (including operational, maintenance and amortized capital costs presented on an annual basis per linear mile) and pipeline injection costs were added to the LCOEs for the on-farm directed biogas and centralized directed biogas scenarios. With respect to all scenarios, the analysis uses an industry-standard 7% discount rate. Notably, more options for anaerobic digestion and large-scale energy production at centralized hubs exist, including options for co-digestion of higher energy content inputs, such as food waste, but researchers chose the most likely and best-known options in an effort to simplify the model's initial run.

---

[26] The Loyd Ray Farms Swine Waste-to-Energy Carbon Offsets Project is a partnership between Duke University, Duke Energy, Google Inc., and Loyd Ray Farms, Inc. The project, located at an 8,640-head feeder-to-finish swine operation, employs an in-ground mixed digester to generate biogas to fuel a 65-kW microturbine. The project also employs an innovative waste management system to meet the North Carolina environmental performance standards for swine farms. For more information, see http://sustainability.duke.edu/carbon_offsets/Projects/loydray.html.

3. RESULTS

The tables below provide the LCOE for production under each scenario at each stage of the REPS (i.e., in 2013, 2015, and 2018 and beyond) and in the aggregate. Data received from industrial sources indicated a range of high- and low-end costs to install and maintain biogas pipelines and to pressurize and inject biogas into the high-pressure existing natural gas pipeline. The costs in the tables below are calculated on the basis of a 20-year operating period. Because the costs could differ based on the way each scenario is implemented, the authors caution against relying on the absolute value of the LCOE in any scenario; rather, the LCOEs are intended as a way to compare scenarios and identify efficiencies.

The analysis also calculates the LCOE for the on-farm electricity production and centralized directed biogas scenarios on the basis of whether biogas is collected at each farm using covered lagoons, mixed digesters, or mixed digesters as part of an innovative animal waste management system. The analysis indicates that the number of farms that will be required to participate to meet each stage of the REPS and the overall 0.20% REPS swine set-aside is affected by whether mixed digesters or lagoon covers are employed. Mixed digesters, which use mixing pumps, flow diverters, and other equipment, are designed to maximize biogas production, and their employment decreases the overall number of farms required to produce the volume of biogas needed to comply with the REPS requirements. **This analysis suggests that use of mixed anaerobic digesters could require as few as 127 farms to meet the REPS requirements in all scenarios compared with as many as 284 farms if covered lagoons are employed.**

Table 8 shows each scenario's LCOE using both low- and high-end pipeline cost estimates. Table 10 shows the total projected cost to implement each scenario, along with the estimated annual electricity generation in megawatt-hours, using the low- and high-end pipeline cost estimates. The amount of electricity generation is different in each scenario due to different equipment configurations. For example, in scenarios involving directed biogas, electricity is assumed to have been generated at an existing combined-cycle natural gas power plant, which can be approximately 15% more efficient than a small-scale on-farm generator or microturbine. The analysis does not consider transaction costs or costs that represent a reasonable rate of return for developers, including payments to farm operators for the biogas or other transaction costs that may be necessary to implement swine WTE projects to scale.

Levelized Cost of Electricity: All Scenarios

Table 9 assumes the lowest biogas pipeline transport and injection cost estimates obtained by the researchers. Notably, the option with the lowest LCOE is the use of mixed digesters for biogas production as part of a centralized directed biogas system. The option with the next lowest LCOE is centralized directed biogas systems that incorporate innovative waste management components, followed by use of on-farm electricity production via mixed digesters.

Table 9. Levelized cost of electricity (LCOE) for each scenario across all stages of the REPS.

		Stage 1		Stage 2		Stage 3		Total	
		Range of $/kWh	*# of Farms*	*Range of $/kWh*	*# of Farms*	*Range of $/kWh*	*# of Farms*	*Range of $/kWh*	*# of Farms*
On-Farm Electricity Production	*Covered Lagoons*	$0.157	86	$0.188	107	$0.179	91	$0.175	284
	Mixed Digesters	$0.111	39	$0.114	46	$0.111	42	$0.112	127
	*Innovative Systems**	+ $0.033	39	+$0.033	46	+$0.038	42	+$0.035	127
On-Farm Directed Biogas	*Covered Lagoons*	$0.238–$0.855	86	$0.296–$0.929	107	$0.249–$0.859	91	$0.262–$0.882	284
Centralized Electricity Production	*Covered Lagoons*	$0.173–$0.28	86	$0.225–$0.251	107	$0.221–$0.41	91	$0.206–$0.313	284
Centralized Directed Biogas	*Covered Lagoons*	$0.093–$0.163	86	$0.127–$0.163	107	$0.127–$0.276	91	$0.116–$0.184	284
	Mixed Digesters	$0.054–$0.094	39	$0.055–$0.102	46	$0.066–$0.138	42	$0.058–$0.111	127
	*Innovative Systems**	+$0.020–$0.021	39	+$0.021–$0.020	46	+$0.024–$0.023	42	+$0.022	127

*Innovative system components would be combined with mixed digester-based systems, not with covered lagoons.

Note: Where inter-farm pipeline transport was required, LCOEs were calculated using the low- and high-end pipeline costs, thus producing a range of costs. LCOE calculations include capital and operating costs over a 20-year period. Costs for innovative systems were represented as increased costs on a per-kWh basis for on-farm electricity production and centralized directed biogas scenarios.

Projected Costs and Annual Electricity Production

Table provides the net present value of the total costs over a 20-year period, calculated using the low-end and high-end biogas transport and injection cost estimates obtained by the researchers and assuming biogas capture with either covered lagoons or mixed digesters. In Appendix B, costs are subdivided into component parts, including equipment for biogas capture, conditioning, transport, electricity generation, and pipeline injection. Costs for individual subgroups that comprise the centralized directed biogas scenario are also displayed in Appendix B.

Table 10. Total costs (in $1,000s) and electricity production (in MWh/year) for biogas systems in each scenario

		Stage 1			Stage 2			Stage 3			Total		
		$1,000s	***MWh/ year***	***# of Farms***	***$1,000s***	***MWh/ year***	***# of Farms***	***$1,000s***	***MWh/ year***	***# of Farms***	***$1,000s***	***MWh/ year***	***# of Farms***
On-Farm Electricity Production	***Covered Lagoons***	$161,851	97,363	86	$193,544	97,133	107	$182,448	96,026	91	$537,842	290,522	284
	Mixed Digesters	$117,924	100,209	39	$121,072	100,237	46	$119,631	101,377	42	$358,627	301,823	127
	Innovative Systems	$153,285	100,209	39	$155,585	100,237	46	$159,925	101,377	42	$468,795	301,823	127
On-Farm Directed Biogas	***Covered Lagoons***	$365,804–$1,316,158	145,344	86	$512,451–$1,607,168	163,251	107	$431,679–$1,486,578	163,405	91	$1,309,934 – $4,409,904	472,000	284
Centralized Electricity Production	***Covered Lagoons***	$170,988–$276,466	93,231	86	$219,866–$244,649	92,176	107	$215,412–$399,031	91,811	91	$606,266–$920,146	277,217	284
Centralized Directed Biogas	***Covered Lagoons***	$162,178–$283,001	163,924	86	$219,053–$282,332	163,251	107	$220,699–$478,263	163,405	91	$601,929–$957,190	490,580	284
	Mixed Digesters	$91,471–$160,814	161,187	39	$93,548–$171,535	159,319	46	$114,290–$238,175	162,882	42	$299,309–$570,524	483,388	127
	Innovative Systems	$126,833 - $196,176	161,187	39	$128,061 - $206,048	159,319	46	$154,585 - $278,469	162,882	42	$409,478 - $680,693	483,388	127

Note: Where inter-farm pipeline transport was required, LCOEs were calculated using the low- and high-end pipeline costs, thus producing a range of costs. Total costs include capital and operating costs over a 20-year period

Projected Biogas Generation Costs for Centralized Directed Biogas Scenario

Table shows the projected cost of generating biogas in the directed biogas scenario. This cost includes the cost of capturing the biogas on each farm, conditioning it in a centralized hub, and injecting it into the natural gas pipeline.[27] The cost can be compared to costs of natural gas that would be supplied to a combined cycle plant (with capital and operational costs included).[28]

Table 11. Cost of generating biogas ($/MMBtu) for the centralized directed biogas scenario over a 20-year period

	Stage 1		Stage 2		Stage 3		Total	
	Range of $/MMBtu	***# of Farms***	***Range of $/MMBtu***	***# of Farms***	***Range of $/MMBtu***	***# of Farms***	***Range of $/MMBtu***	***# of Farms***
Covered Lagoons	$12.97 – $22.63	86	$17.59–$22.67	107	$17.71–$38.37	91	$16.09–$25.58	284
Mixed Digesters	$7.44 – $13.08	39	$7.70–$14.12	46	$9.20–$19.17	42	$8.12–$15.47	127
Innovative Systems	$10.32 – $15.96	39	$10.54–$16.96	46	$12.44–$22.41	42	$11.11–$18.46	127

Note: The range of costs reflect estimates that span low to high pipeline cost estimates.

[27] According to data from the U.S. Energy Information Administration, the average price of natural gas for electric power generation in 2012 was $3.56/MMBtu. See http://www.eia.gov/dnav/ng/hist/n3045us3m.htm. The Henry Hub spot price for natural gas as of April 25, 2013 was $4.23/MMBtu.

[28] An estimate of the cost of generation at a combined-cycle natural gas power plant is approximately $0.044/kWh. This estimate includes only fuel and operating costs, and does not include capital costs. It assumes a 20-year levelized natural gas price of $4.88/MMBtu, based on projections for natural gas costs for the electricity sector from the Energy Information Administration Annual Energy Outlook 2012. (Personal communication, David Hoppock, Duke University). See also Rachel Cleetus, *et al.* 2012, Ripe for Retirement: The Case for Closing America's Costliest Coal Plants, Union of Concerned Scientists, p. 76.

Greenhouse Gas Emission Reduction Potential; Projected Carbon Offset Generation and Projected Income Potential

Because swine WTE projects involve the capture and destruction of methane, which is a greenhouse gas (GHG) with 21 times the global warming potential of carbon dioxide, they provide significant GHG emission reduction benefits. The analysis therefore examined each scenario's potential to reduce GHG emissions, which could be translated to carbon offset credits that could be used to comply with greenhouse gas emission reduction requirements. In California, for example, the California Air Resources Board recognizes carbon offset credits generated via projects that capture and destroy methane from livestock manure management systems, including swine WTE projects, as compliance worthy under the state's cap-and-trade market regime, thereby allowing capped entities to purchase carbon credits to comply with GHG reduction mandates.[29] For the purposes of this analysis, carbon offset payments were assumed to be \$10/$MTCO_2e$, which could generate between \$13.5M and \$13.7M on an annual basis for mixed digester and lagoon cover-based systems, respectively.[30]

Table 12 provides the range of estimated GHG emission reductions achievable through compliance with the REPS swine waste targets for each stage of the REPS and for the REPS overall. Greenhouse gas emission reductions are limited by the baseline emissions calculated for each farm. The use of mixed digesters or covered lagoons will influence the number of farms that would be needed to achieve the same or similar level of reductions. It should be noted that swine WTE projects are capable of generating both carbon offset credits and renewable energy certificates (RECs). The projects generate carbon offset credits solely by destroying the methane in the biogas, while RECs are generated by producing electricity from a renewable energy source. See Appendix C for a discussion of the calculation methods supporting the carbon offset generation and cost estimate calculations.

Table 12. Estimated carbon offset generation in metric tons of carbon dioxide equivalent per year ($MTCO_2e$/year) from biogas systems' destruction of methane

	Stage 1	Stage 2	Stage 3	Total
	$MTCO_2e$/year	*$MTCO_2e$/year*	*$MTCO_2e$/year*	*$MTCO_2e$/year*
Estimated Range of GHG Reductions	450,467 - 458,117	445,247 - 456,235	445,206 - 456,667	1,350,920 - 1,371,019

Discussion of Results and Influencing Factors

After applying the OptimaBIOGAS model to each of the four scenarios, researchers were able to examine the potential for economies of scale through the centralization of either electricity production or the conditioning and compression of the biogas for pipeline injection. The model indicates that transport of biogas to a centralized hub for heavy conditioning (i.e., conditioning to specifications required for

[29] The credits are also eligible to be traded in the voluntary carbon market via registries such as the Climate Action Reserve.
[30] See footnote 19.

injection of biogas into the natural gas pipeline) and injection into the pipeline (the centralized directed biogas scenario), assuming low-end cost estimates, achieves significant economies of scale. But no economies of scale were discernible through the transport of biogas to a hub for centralized electricity production (the centralized electricity production scenario).[31] The reason is that optimal centralized hubs selected by the model merely consist of a bank of multiple small-scale microturbines; therefore, a centralized biogas system, whereby electricity would be produced at a hub, has generation equipment costs similar to those of the on-farm electricity production scenario.[32] Conversely, economies of scale are present for the centralization of biogas conditioning and compression (the centralized directed biogas scenario), because larger, more efficient equipment can be installed at a central hub, which dramatically reduces costs compared with installing heavy conditioning equipment on each farm. In addition to these economies of scale, the centralized directed biogas scenario is further distinguished by the fact that the electricity is generated at a combined cycle natural gas power plant, which is up to 15% more efficient than an on-farm generator or microturbine.

Comparing all four scenarios on the basis of the LCOE identified for each through this analysis—and assuming lowest-cost estimates for pipeline transport and injection—indicates that centralized processing of biogas for pipeline injection (centralized directed biogas) is the least-cost option, followed by on-farm electricity production (see Figure 18). Assuming highest-cost estimates for inter-farm biogas transport and pipeline injection, on-farm electricity production becomes the least-cost option, followed by centralized directed biogas. Electricity production at a centralized hub is the next least-cost option, assuming limited electricity production equipment options, with on-farm directed biogas the highest-cost option, and the one least likely to be implemented at all stages of the REPS.

This analysis assumes no particular business model or financing approach, nor does it attempt to determine which participants would pay which costs, but several options exist. In almost any scenario and to accomplish swine WTE to scale, significant coordination as well as coordinated financing is likely to be required. The researchers recommend that additional analysis be conducted to investigate the options for structuring an appropriate and efficient business model to deploy swine WTE under various scenarios. The structure of the business model or financing approach would likely affect the LCOE and may influence the final scenario or combination of scenarios pursued.

The analysis indicates that the competitiveness of the scenarios is wholly dependent on pipeline transport and injection costs. The LCOEs calculated for each scenario are summarized in Figure 14. Given the most favorable assumptions—which include the low-end pipeline costs, the use of mixed digesters (as opposed to covered lagoons), and the operation of the system for 20 years—the analysis determined that the

[31] For biogas injection into the natural gas pipeline, researchers used a general specification requiring the removal of carbon dioxide (CO_2), hydrogen sulfide (H_2S), and other impurities from the biogas stream such that the gas delivered to the pipeline must be comprised of 98% methane, no more than 2% CO_2, and less than 4 ppm H_2S. In addition, the gas must be pressurized to 800 pound-force per square inch (psi). This specification does not necessarily reflect the requirements of any particular pipeline operator in North Carolina, as many pipeline operators are still examining the biogas injection issue before releasing biogas specification requirements.

[32] The model selected microturbines rather than internal combustion engines because of the requirement that biogas be conditioned and pressurized to specifications necessary for injection into the natural gas pipeline. Therefore, the model determined that it would be less expensive to purchase a microturbine than an internal combustion engine plus a gas conditioning unit capable of removing carbon dioxide and hydrogen sulfide and of dehumidifying the gas to levels necessary to operate an internal combustion engine.

centralized directed biogas scenario has the lowest LCOE at \$0.058/kWh. Given high-end estimates for pipeline costs, the analysis determined that the centralized directed biogas and the on-farm electricity production scenarios have nearly identical LCOEs, at \$0.111/kWh and \$0.112/kWh, respectively, when mixed digesters are used. If covered lagoons are used to collect the biogas, the LCOE for the on-farm electricity production scenario is \$0.175, and the LCOE for the centralized directed biogas scenario is \$0.116 when low-end pipeline costs are applied and \$0.184 when high-end pipeline costs are applied.

Even when the highest pipeline costs are applied, centralized directed biogas has a lower LCOE than on-farm electricity production for stages 1 and 2 of the REPS. However, the LCOE for centralized directed biogas in stage 3 is almost three cents higher than that for on-farm electricity production when the highest pipeline costs are used, hence, the total LCOE for centralized directed biogas is higher in that case. The analysis therefore indicates that it might be worthwhile to pursue a combined approach whereby centralized directed biogas is implemented for stages 1 and 2 of the REPS, and on-farm electricity production is used to meet the requirements of the final stage. The reason that centralized directed biogas can compete with on-farm electricity production, even with significantly higher costs, is that it would ultimately result in electricity generation at a much more efficient facility, such as an existing combined-cycle power plant, and therefore would ultimately produce much more energy per MMBtu of biogas.

The other two scenarios—on-farm biogas conditioning for direct injection to the pipeline (on-farm directed biogas) and centralized electricity production—proved to be much less attractive than on-farm electricity production and centralized directed biogas. On-farm directed biogas faces extremely high capital costs because each farm would need a biogas conditioning unit to remove carbon dioxide and hydrogen sulfide as well as a considerable amount of expensive high-pressure pipeline to connect each farm to the natural gas pipeline. A centralized electricity production approach is expensive because it does not achieve economies of scale; the centralized generation units are simply large collections of small-scale generation units, thus essentially no cost savings can be achieved from centralization, whereas establishing an inter-farm pipeline network entails significant costs.

Overall, the model indicates that significant savings through the transport of biogas for centralized conditioning and pipeline injection can be achieved *provided that pipeline transport and injection costs can be contained*. The factors that affect the cost of pipeline installation include the cost of acquirement of easements for rights of way and whether the pipeline path would encounter issues with protected habitats, such as wetlands or endangered species habitat. If costs can be kept to the lower end of the range, pipeline injection could be a preferable choice, as it routes biogas to existing power plants, which are much more efficient than distributed smaller-scale microturbines or generators. However, applying a conservative estimate for pipeline construction and injection costs from centralized gas conditioning hubs could increase the costs to pursue compliance of the REPS via a centralized directed biogas approach, thereby making the on-farm electricity production option more attractive by comparison. Further analysis to narrow the potential range of pipeline costs could be used to ascertain differences between the two scenarios in order to better predict the most optimal approach.

Importantly, use of mixed anaerobic digesters would reduce the number of participating farms required to meet the REPS, reducing its costs, even below those of lagoon-cover biogas harvesting methods. Limiting the number of farms required to participate may be desirable to developers, depending on policy considerations and the ease or difficulty of inter-farm pipeline construction and maintenance, which makes the mixed digester option even more attractive.

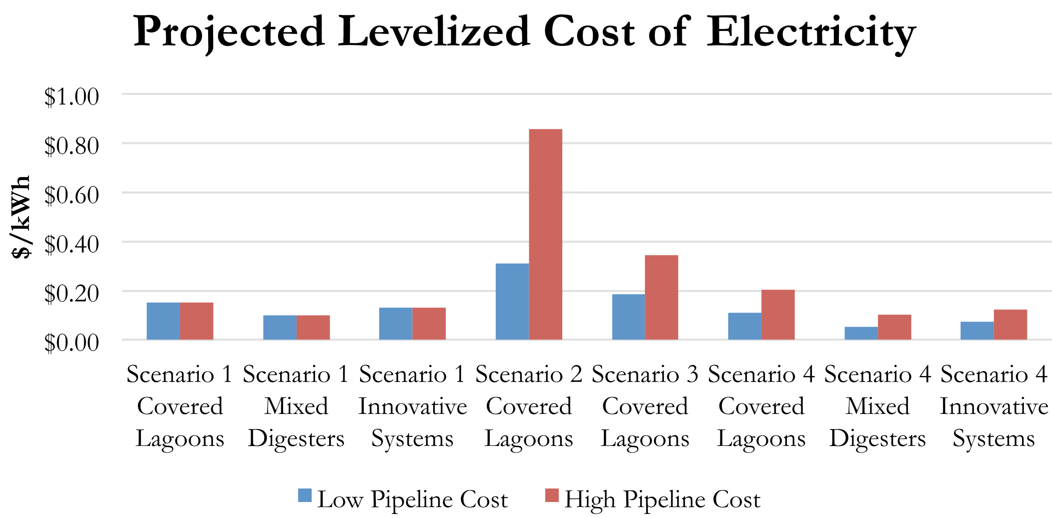


Figure 18. Levelized cost of electricity (LCOE) in dollars per kilowatt-hour ($/kWh) of the four scenarios evaluated, assuming systems are operated for 20 years. The LCOEs presented here represent the total projected costs to generate electricity in fulfillment of the REPS 0.20% swine set-aside requirement under each scenario evaluated by the OptimaBIOGAS model.

Statewide Results

In addition to the scenarios described above, researchers used OptimaBIOGAS to rank the biogas potential for all swine farms in North Carolina. For the statewide analysis, researchers assumed that all farms would generate electricity on an individual basis for transfer to the electric power grid, similar to the on-farm electricity production scenario. They estimated that if all farms participated in generating and collecting biogas, and if covered lagoons were employed, the total output would be approximately10 million MMBtu/year and 720,000 MWh of electricity per year, which is enough electricity to power more than 54,000 homes. If mixed digesters were employed, the system would generate an estimated 19.9 million MMBtu/year and 1,940,000 MWh of electricity per year, which is enough electricity to power more than 140,000 homes as well as to meet more than 700% of the total REPS requirements. It is also enough biogas to supply more than 12% of the natural gas used for electric power generation in North Carolina in 2012.[33] More research and analysis are recommended to more accurately determine a biogas generation rate at which WTE systems would become economically viable on a farm-by-farm basis and thereby to determine an appropriate expectation for statewide deployment of swine WTE beyond the REPS.

[33] Figures were compiled from the U.S. Energy Information Administration's Form EIA-923 detailed data, available at http://www.eia.gov/electricity/data/eia923/.

4. FURTHER RECOMMENDED ANALYSIS AND OUTREACH

The analysis marks a major stride forward in terms of identifying the best approaches and evaluating new options for compliance with REPS swine set-asides. But additional study is recommended to discern more specifically the costs of each approach and to identify and develop a strategy for addressing potential barriers to implementation. That strategy would include optimal financing options and business models as well as an organized policy approach. Policy considerations include methods for supporting improved waste management by participating producers to achieve environmental, health, and economic benefits and the full economic costs of installing innovative animal waste management systems. Options for achieving some but not necessarily all of the environmental performance standards should be evaluated.

Notably, the analysis assumes use of specific—but not necessarily the full range of—processes for biogas capture. As large-scale waste-to-energy systems are developed, other methods for on-farm biogas capture as well as electricity production at the farm and centralized level, as the case may be, should be considered as they could affect a scenario's ultimate LCOE. As with all modeling analyses, results of the OptimaBIOGAS analysis need to be tested in real-world conditions to confirm the practicalities of the model's core assumptions.

Indeed, the OptimaBIOGAS analysis is based on a variety of assumptions that require further investigation. These assumptions include the actual (rather than estimated) cost to inject biogas at specific injection points, the effect of injected biogas on the receiving gas stream and pipeline, and the availability (or lack of availability) of additional (and preferable) equipment and methods for biogas capture and processing. For the expedience of this analysis, options were limited to the most common methods for capturing biogas from anaerobic digestion, but a variety of additional options, including heated digesters and aboveground digesters, should be evaluated. Co-digestion of swine waste with other waste streams, such as food waste or other agricultural wastes, which can produce more energy potential (BTUs) per unit of volume than digestion of swine waste alone, should also be investigated.

Another recommendation for study is the interest of the individual swine operations that have been identified as optimal for participation and whether they would be appropriate candidates for farm expansion, which could increase biogas production on a per-farm basis and thereby decrease the overall number of farms needed for participation. In developing strategies to implement either a centralized or individual approach to swine WTE, outreach is needed to entities such as swine producers, extension service specialists and conservation district officers, representatives of the North Carolina agriculture and pork industries (including integrators), and rural economic development specialists within the geographic area identified by the analysis (i.e., Duplin and Sampson counties).

Other issues for analysis include specific barriers that might impede implementation of least-cost scenarios—such as access to capital, permitting issues, and siting—as well as programs and incentives that could support swine WTE, such as tax credits and conservation payments. In terms of transmission of power from individual farms to the power grid, analysis is needed to determine whether farms are supplied by single-phase or three-phase power; the equipment used for electricity generation will most likely—and more efficiently—produce three-phase power. Use of lagoon covers also requires additional study: because nitrogen accumulates in the wastewater and swine farmers ultimately apply that water to their land, it must be determined if participating farms have enough land to assimilate additional nutrients and ammonia at the rate they would volatilize to the atmosphere in an open-air lagoon in order to comply with nutrient management requirements.

If costs prove low enough, further analyses could consider whether swine WTE could compete with other renewable energy sources to supply the general REPS or even compete with traditional energy sources, thereby expanding opportunities for swine WTE beyond the cluster of farms identified by the present analysis. This analysis focused on direct costs and monetized benefits; to fully capture the economic impact of these options, further research is needed to assess the full range of non-monetized and indirect economic benefits, particularly for rural communities and in terms of job growth. Also needed are analyses of financing scenarios and ownership models that would contribute to the development of realistic business cases. Any future analyses should include consideration of different entities for developing and overseeing implementation of swine WTE systems, such as private entities, nonprofits, and local or state governments. The latter are of particular interest where systems are contained within one to two counties and extension officers could be deployed to assist with implementation and provide expertise. Creative structures for payments of carbon offsets and RECs could also be considered, as should methods for protecting against the risk that biogas producers will cease to operate or otherwise withhold their supply of biogas. Finally, other uses for biogas produced from swine operations, such as for transportation fuel or as a substitute for natural gas-derived products, would be worthwhile to evaluate the full potential of the swine biogas resource.

Costs derived through this analysis have been simplified and do not include costs, payments, or cost-sharing opportunities with respect to this supply. They also do not include the potential for reductions in equipment costs that might be achieved through bulk purchasing or production advances. They *do* serve as a starting point for further exploration of options.

Other questions for future study include the following:

- Could waste heat from the electrical generation process (on individual farms) be used to increase biogas output, reduce costs to operate innovative animal waste management systems, or both?
- What is the effect on LCOEs of employing heated digesters?
- What alternatives to existing innovative animal waste management systems are available or in development?
- Are other options available for improving waste management short of compliance with the environmental performance standards?
- What is the effect on LCOEs of allowing use of larger digesters for farm expansion?
- What are the costs and benefits associated with the addition of other feedstock materials, such as food waste, to the digesters?
- How could future analyses be designed to model hypothetical changes to the REPS requirements?

5. CONCLUSIONS

This analysis demonstrated that OptimaBIOGAS can inform the development of cost-effective designs for deploying a biogas-to-electricity infrastructure under a range of spatial and economic constraints. The series of models was specifically designed to provide strategic options for meeting the North Carolina REPS. Four scenarios were explored. Among the key points illustrated by this study are the following:

- In many circumstances, centralization of electricity production can be more expensive than on-farm electricity generation because increased capital costs outweigh efficiency gains realized through economies of scale.

- Significant savings in the cost of biogas transport to an existing gas pipeline can be achieved by networking multiple biogas sources into a pipeline system rather than building individual pipelines from each source.

- Although additional transport costs in scaling up the system are substantial, the equipment and operation cost savings of doing so are likely to be even more significant and thus are a greater influence on the design of the biogas infrastructure and accentuate the possibility of economies of scale.

- The greatest cost savings and electricity generation could be achieved where the design of biogas infrastructure is scaled up, the centralized conditioning and pressurization hub is connected to a natural gas pipeline, and electricity is generated using existing conventional natural gas power plants.

- Results of the spatial and cost analysis must be tested in real-world scenarios to confirm that pipeline injection is more practical than electricity production.

- The analysis also considers the greenhouse gas benefits of large-scale swine waste-to-energy systems and the economic benefits of generating carbon offsets.

- The full benefits, true costs, anticipated revenues, and effects of adding components of innovative animal waste management systems onto biogas-capture systems should be further investigated.

- Other sources of income from innovative waste management systems, such as farm expansion, reduced mortalities, and conversion to cash crops, should be better explored to identify cost benefits of such systems, which yield significant environmental benefits.

- As little as 7% of North Carolina swine farms are needed to meet the REPS requirements; the maximum potential of swine WTE in the state, given assumed cost feasibility based on a 7,500 MMBtu/year threshold, is 387 farms or 18% of the state's swine farms.

This report highlights the importance of systematic planning for biogas infrastructure. Economies of scale could provide incentives to the swine industry, utilities, and third-party entities to promote and invest in biogas-to-electricity generation systems.

A SPATIAL-ECONOMIC OPTIMIZATION STUDY OF SWINE WASTE–DERIVED BIOGAS INFRASTRUCTURE DESIGN IN NORTH CAROLINA

TECHNICAL APPENDICES

Darmawan Prasodjo*
Tatjana Vujic†
David Cooley†
Ken Yeh*
Meng-Ying Lee*

*Nicholas Institute for Environmental Policy Solutions, Duke University

† Duke Carbon Offsets Initiative, Duke University

Appendix A. Data and Assumptions

A.1. Pipeline Cost Data

Pipeline cost data were obtained from industry sources. The costs provided here are general in nature; any developer seeking to install new biogas pipeline in North Carolina should contact the appropriate gas utility, pipeline operator, or both for more specific information. Table A.1.1 includes the low- and high-end cost of service estimates for pipeline, including installation and ongoing maintenance. Table A.1.2 includes the annual cost for operating an interconnection point to the natural gas pipeline network.

Table A.1.1. Annual pipeline cost of service estimates for the biogas pipeline network. Costs are presented as annual costs over a 15-year period on a per-mile basis and include capital, installation, operations and maintenance, and gas transport fees. Low-pressure pipes would be used to collect biogas between farms, whereas high-pressure pipes would be used to transport biogas between the two-stage compressor and the existing natural gas pipeline.

	Low Pressure Pipe		High Pressure Pipe	
Pipe Size (inches)	Low end of range	High End of Range	Low End of Range	High End of Range
2”	$6,947	$24,809	$34,733	$228,238
4”	$9,924	$29,771	$59,541	$396,935
6”	$13,894	$34,733	$198,468	$793,870
8”	$19,848	$44,656	$248,085	$992,337
Right of way	$11,909	$57,556	$11,909	$57,556

Table A.1.2. Annual cost of service over a 15-year period for an interconnection point to the existing natural gas pipeline network.

Annual Cost of Service for Natural Gas Transmission Pipeline Interconnection Point	
Low End of Range	High End of Range
$59,995	$187,943

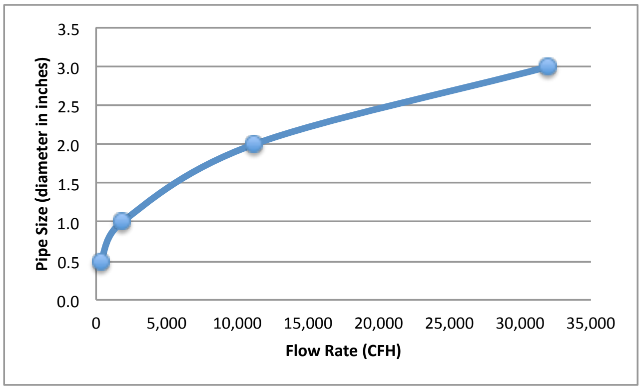


Figure A.1.1. Flow vs. pipe size (uncompressed gas pipeline).

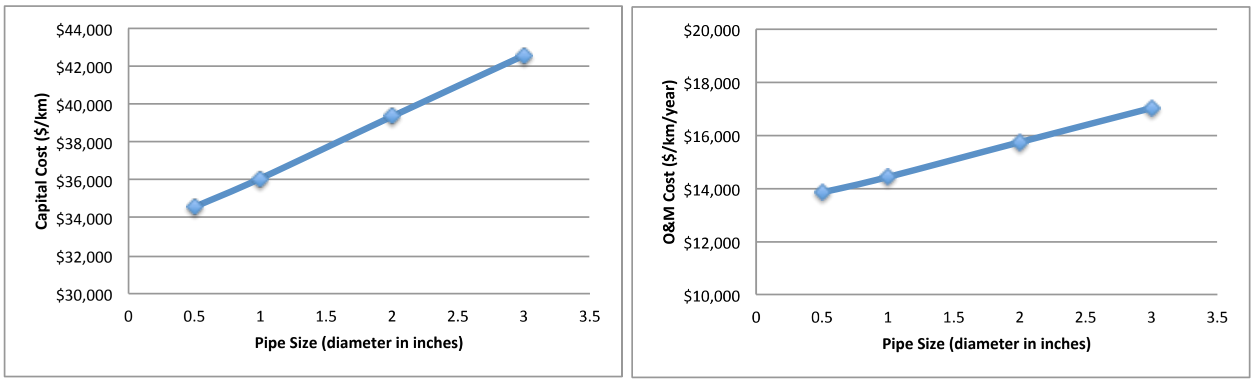


Figure A.1.2. Pipe size vs. capital cost and pipe size vs. O&M cost.

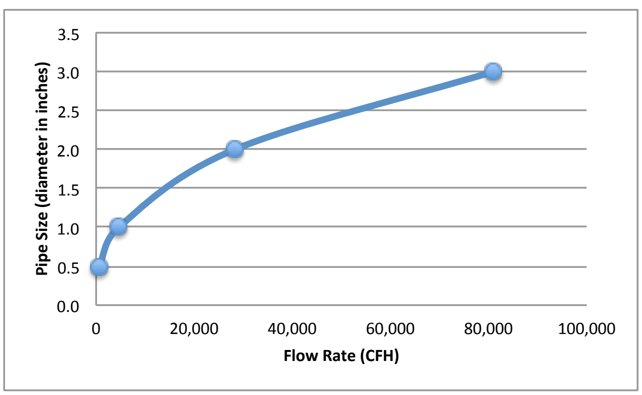


Figure A.1.3. Flow vs. pipe size (compressed gas pipeline).

A.2.Biogas Conditioning Units: Water removal

The following tables and figures summarize the specification data for biogas water removal conditioning units used in modeling. Table A.2.1 summarizes the costs and flow rates by conditioning model. Figure A.2.1 shows the relationships between capacity and the capital cost and the O&M cost.

Table A.2.1. Biogas conditioning unit specification data (water removal)

Biogas Conditioning Unit	Unit Cost ($/unit)	Operation & Maintenance Cost ($/year)	Operating Feed Flow (SCFH)	Product Output Flow (SCFH)	Technology Used for Conditioning
Unison	$192,000	$13,500	1,500	1,450	Glycol chiller
Unison	$266,000	$13,500	4,200	4,100	Glycol chiller
Unison	$550,000	$16,500	9,000	8,800	Glycol chiller
Unison	$810,000	$25,000	12,000	11,500	Glycol chiller

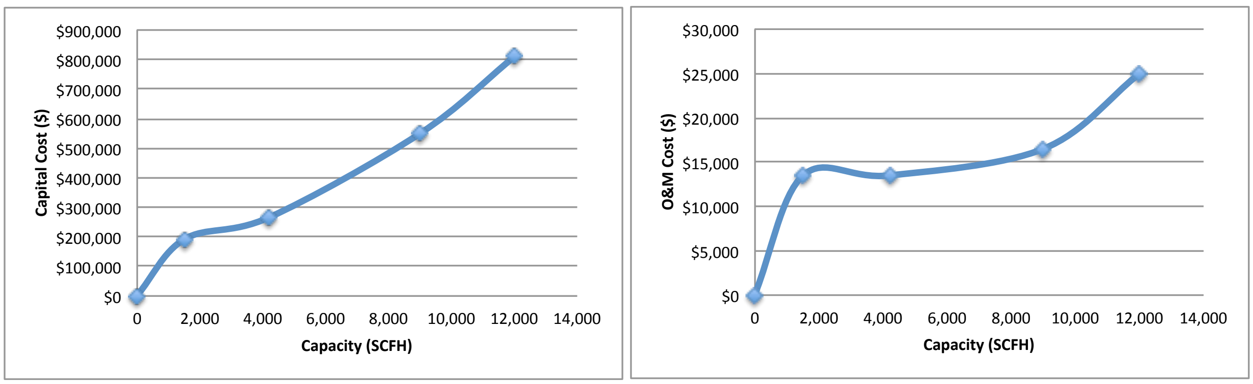


Figure A.2.1. Capacity vs. capital cost and capacity vs. O&M cost.

A.3.Biogas Conditioning Units: Natural Gas Level

The following tables and figures summarize the specification data for biogas heavy conditioning units used in modeling. Table A.3.1 summarizes the costs and flow rates by conditioning model. Figure A.3.1 shows the relationships between capacity and the capital cost and the O&M cost.

Table A.3.1. Biogas conditioning unit specification data (natural gas level)

Biogas Conditioning Unit	Unit* Cost ($/unit)	Operation & Maintenance Cost ($/year)	Operating Feed Flow (SCFH)	Product Output Flow (SCFH)	Impurities Removed (e.g. water, and/or CO_2, and or H_2S.)	Technology Used for Conditioning
Guild	$422,500	$36,535	6,000	3,240	Water,H_2S,CO_2,VOC	PSA
Guild	$1,385,000	$86,600	21,000	11,880	Water,H_2S,CO_2,VOC	PSA
Guild	$1,500,000	$132,000	42,000	23,700	Water,H_2S,CO_2,VOC	PSA
Guild	$1,900,000	$315,100	72,000	40,680	Water,H_2S,CO_2,VOC	PSA
Guild	$2,600,000	$526,200	120,000	67,740	Water,H_2S,CO_2,VOC	PSA
Guild	$4,300,000	$1,276,000	300,000	169,380	Water,H_2S,CO_2,VOC	PSA

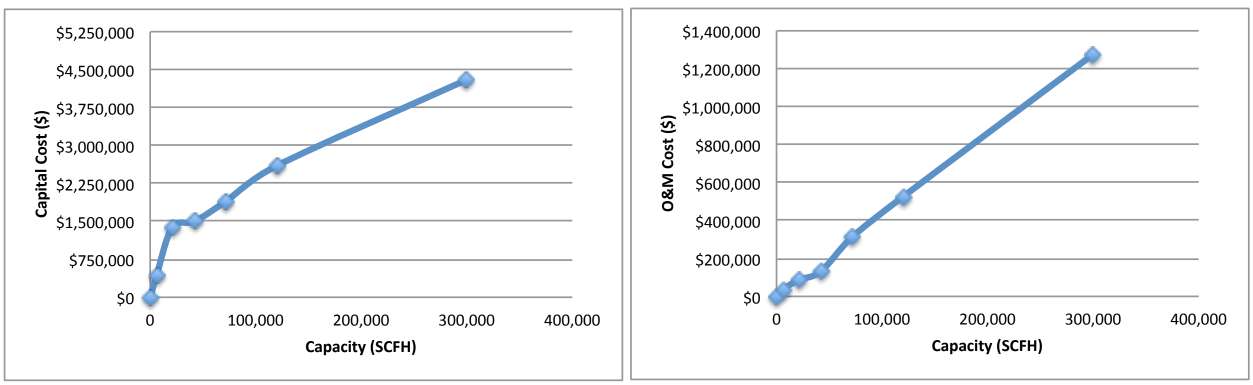


Figure A.3.1. Capacity vs. capital cost and capacity vs. O&M cost.

A.4. Biogas Compressor

The following tables and figures summarize gas compressor specifications data used in our modeling. Table A.4.1 summarizes the costs and flow rates by compressor model. Figure A.4.1 shows the relationships between capacity and the capital cost and the O&M cost.

Table A.4.1. Biogas compressor specification data

Compressor Model	Unit Cost ($/unit)	Operation & Maintenance Cost ($/year)	Input Flow Rate (SCFH)	Input Flow Pressure (psi)	Output Flow Rate (SCFH)	Output Flow Pressure (psi)
Regression	$132,500	$9,465	6,000	100	5,695	800
GE Gemini	$200,000	$16,400	21,000	100	19,920	800
GE Gemini	$225,000	$45,500	42,000	100	39,780	800
GE Gemini	$325,000	$119,900	72,000	100	68,220	800
GE Gemini	$450,000	$193,800	120,000	100	113,700	800
GE Gemini	$600,000	$474,000	300,000	100	284,220	800

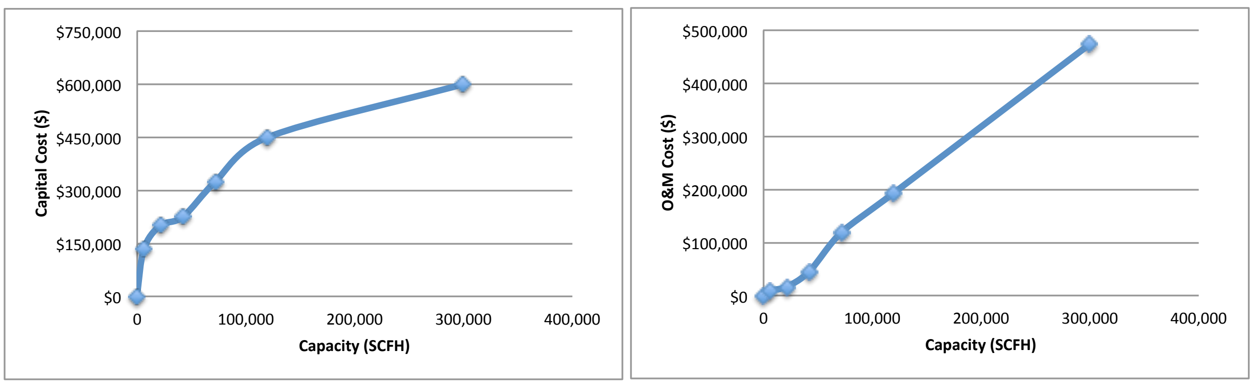


Figure A.4.1. Capacity vs. capital cost and capacity vs. O&M cost.

A.5. Biogas Electric Generator

The following tables and figures summarize biogas electric generator specifications data used in modeling. Table A.5.1 shows the fuel type, generation rating, fuel consumption, and cost by generator model. Figure A.5.1 shows the relationships between fuel consumption capacity and the capital cost, and the O&M cost. Figure A.5.2 shows the relationship between fuel input and electricity generation capacity.

Table A.5.1. Biogas electric generator specification data

Generator model	Fuel Type (Biogas/ Natural Gas)	Power Generation Capacity (kWh)	Fuel Consumption Rate (SCFH)	Generator Cost ($/ unit)	Operation & Maintenance Cost ($/ year)	Energy Conversion Efficiency (%)
Caterpillar	Natural Gas	60	1,650	$85,000	$15,000	31
Caterpillar	Natural Gas	150	1,840	$155,000	$25,000	30
Caterpillar	Natural Gas	600	4,860	$850,000	$100,000	33
Caterpillar	Natural Gas	1,000	8,865	$1,500,000	$150,000	33
GE	Natural Gas	320	3,420	$1,325,000	$73,584	37.2
GE	Natural Gas	613	6,300	$1,740,000	$113,880	38.1
GE	Natural Gas	823	8,400	$1,900,000	$140,160	38.3
GE	Natural Gas	1,029	10,320	$2,085,000	$157,680	39

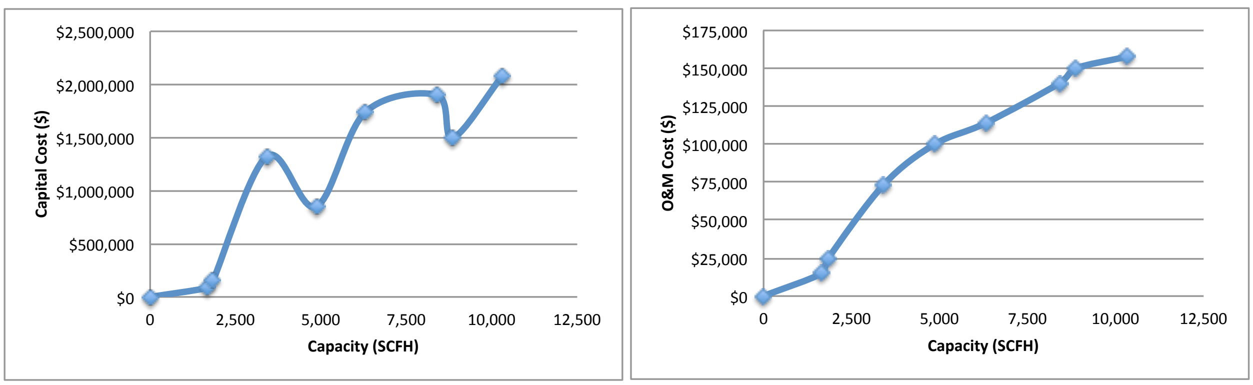


Figure A.5.1. Gas consumption capacity vs. capital cost and gas consumption capacity vs. O&M cost.

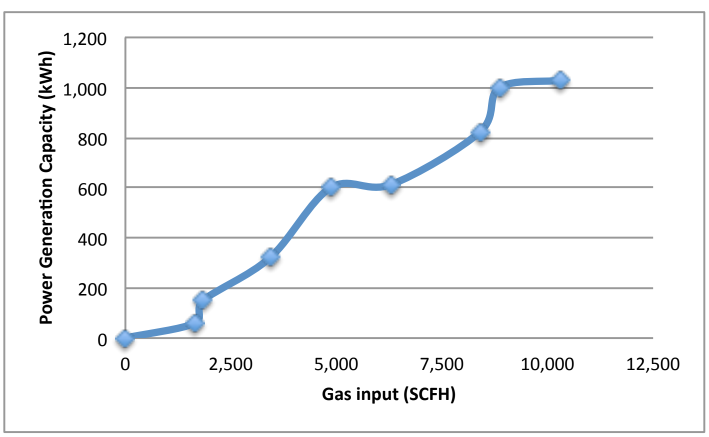


Figure A.5.2. Gas consumption vs. power generation capacity.

A.6. Electricity Generation

The following tables and figures summarize micro-turbine specifications data used in modeling. Table A.6.1 shows the fuel type, generation rating, fuel consumption, and cost by turbine model. Figure A.6.1 shows the relationships between fuel consumption capacity and capital cost, and the O&M cost. Figure A.6.2 shows the relationship between fuel input and electricity generation capacity.

Table A.6.1. Electricity generation specification data

Generator model	Fuel Type (Biogas/ Natural Gas)	Power Generation Capacity (kWh)	Fuel Consumption Rate (SCFH)	Generator Cost ($/ unit)	Operation & Maintenance Cost ($/ year)	Energy Conversion Efficiency (%)
Capstone	Biogas	65	1,500	$106,500	$10,000	33
Capstone	Biogas	200	4,000	$325,000	$25,500	33
GE	Biogas	320	7,020	$1,575,000	$78,840	36.3
GE	Biogas	613	12,600	$1,990,000	$131,400	38.1
GE	Biogas	823	16,800	$2,150,000	$157,680	38.3
GE	Biogas	1,029	20,580	$2,335,000	$175,200	39

Figure A.6.1. Gas consumption capacity vs. capital cost and gas consumption capacity vs. O&M cost.

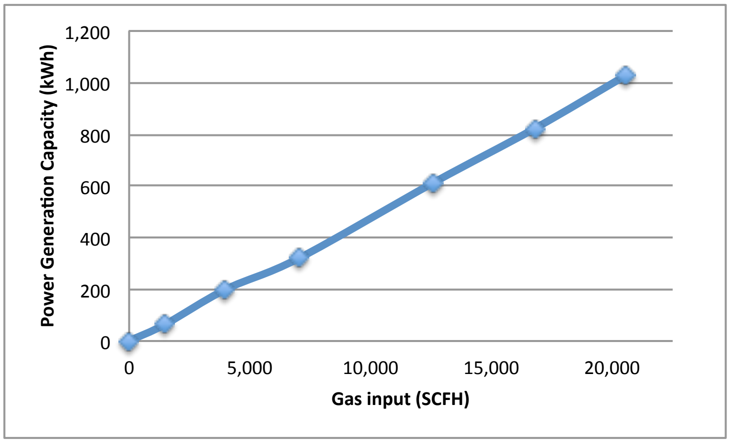


Figure A.6.2. Gas consumption vs. power generation capacity.

A.7. Biogas Capture

The analysis evaluated two on-the-ground biogas projects at swine farms in North Carolina to estimate costs for biogas capture, including the Loyd Ray Farms project, a joint project of Duke University, Duke Energy, and Google, Inc., and the Butler Farms project, which was developed by Environmental Fabrics, Inc. Plastic Fusion Fabricators, Inc., provided data on the cost of covering existing lagoons. The Loyd Ray Farms project, which employs a mixed digester and which qualifies as an innovative system, was also used to estimate the costs of installing innovative systems at biogas projects. Table A.7.1 shows the costs used to determine the per-head cost of installing a mixed digester and innovative system.

Table A.7.1. Cost to capture biogas on a per-head basis. Data from the Loyd Ray Farms Swine Waste to Energy project.

Component	Captial Cost (per head)	
	Biogas Capture	Innovative System
Site preparation	$7.40	$3.99
In-ground lined and covered mixed anaerobic digester	$16.97	$4.79
Pumps, Piping, and Appurtenances	$13.51	$28.82
Equipment building and other construction	$1.66	$2.60
Total	**$39.55**	**$40.19**

To determine the cost of covering existing lagoons, rather than installing new mixed digesters, farms selected in the analysis were located using Google Earth, and the surface area of their existing lagoons was estimated. A subsample of the data was confirmed using swine farm permit records maintained by the North Carolina Division of Water Quality. The analysis assumed a cost of $3.50 per square foot to cover the lagoons—a cost based on a range of costs supplied by Plastic Fusion Fabricators, Inc.

A.8. Biogas Production Rates

Table A.8.1.

MMBtu/year per nominal head				
Farm Type	Covered Lagoons		Mixed Digesters	
	Methane (CH_4) Generated (cubic ft./yr.)	Btu generated (MMBtu/yr.)	Methane (CH_4) Generated (cubic ft./yr.)	Btu generated (MMBtu/yr.)
Boar stud	1150	0.665	2300	1.33
Farrow-to-wean	1182.5	0.685	2365	1.37
Farrow-to-feeder	1602.5	0.93	3205	1.86
Farrow-to-finish	18,421.5	10.65	36843	21.3
Feeder-to-finish	2336	1.355	4672	2.71
Wean-to-feeder	420	0.25	840	0.5
Wean-to-finish	2067.5	1.2	4135	2.4
Gilts	2336	1.355	4672	2.71

Farm type definitions:

Boar stud: An operation housing male domestic swine suitable for breeding.
Farrow-to-wean: An operation housing pigs during the period from birth to weaning.
Farrow-to-feeder: An operation housing pigs during the period from birth until they are moved to a feeder-to-finish operation.
Farrow-to-finish: An operation that contains all production phases, from breeding to gestation to farrowing to nursery to grow-finishing to market.
Feeder-to-finish: An operation that grows pigs to market weight.
Wean-to-feeder: An operation housing pigs after they have been weaned until they are moved to a feeder-to-finish operation.
Wean-to-finish: An operation housing pigs after they have been weaned that grows them to market weight.
Gilts: An operation housing young female pigs up to six months old.

For more information, see U.S. EPA Ag 101 Pork Glossary:
http://www.epa.gov/agriculture/ag101/porkglossary.html

A.9. Centralized Directed Biogas Farm Configurations

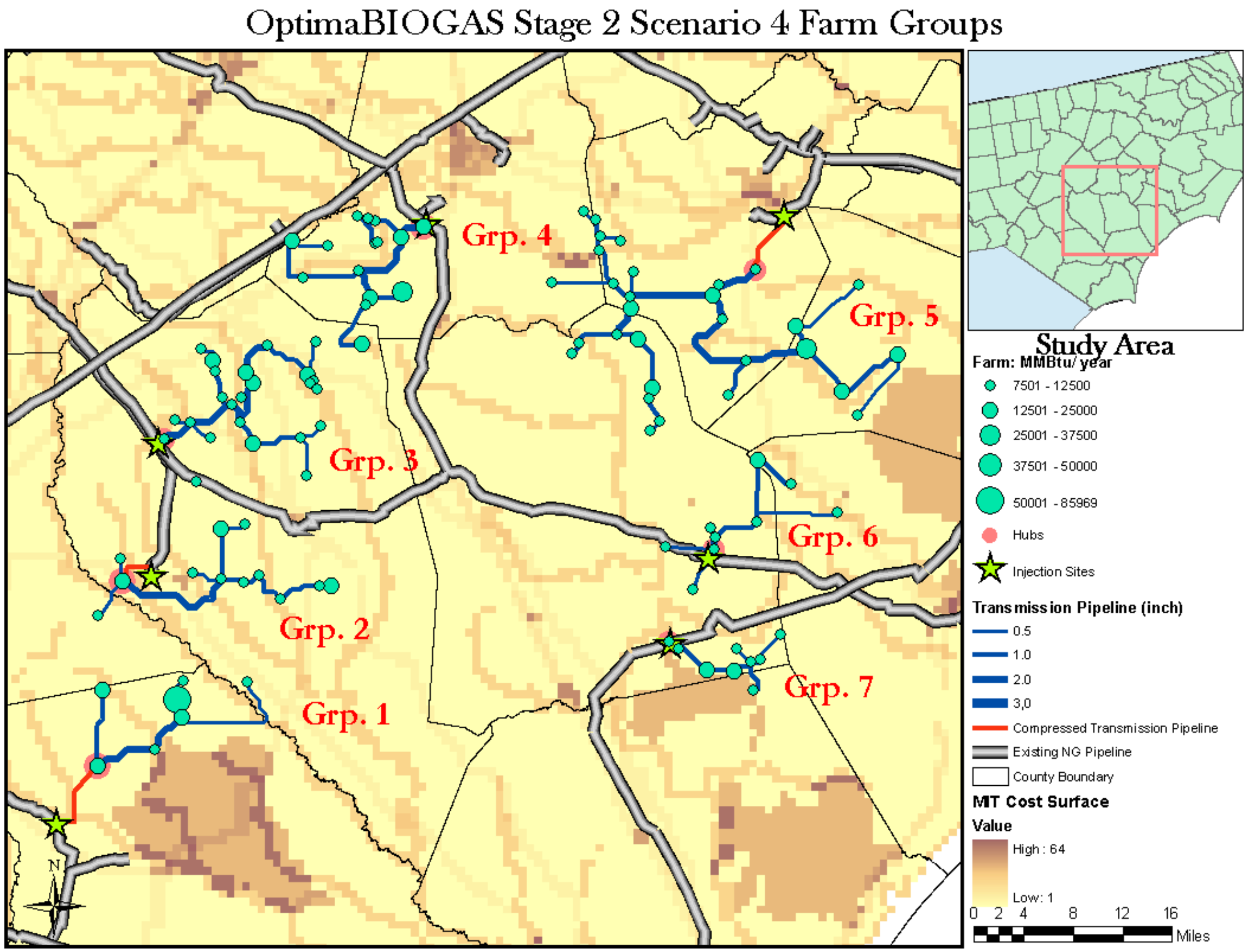


Figure A.9.1. Individual farms, farm clusters, pipeline configurations, and hubs necessary to fulfill the centralized directed biogas scenario for stage 2 of the REPS, assuming the use of covered lagoons for biogas capture. The subgroups (i.e., Grp. 1, Grp. 2, etc.) are groupings of farms that would each have a single injection point to the existing natural gas pipeline, as shown by the stars in the figure.

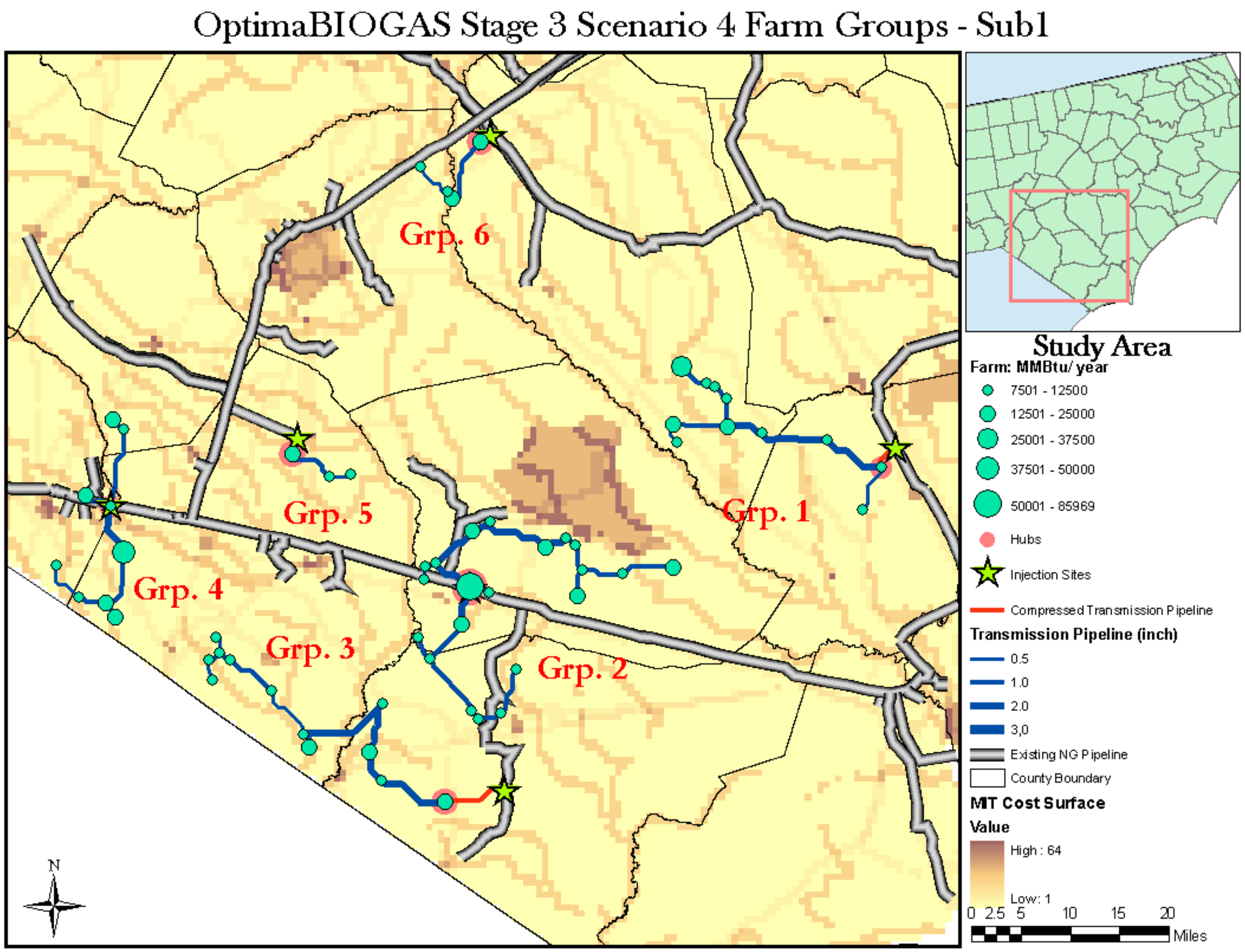


Figure A.9.2. Individual farms, farm clusters, pipeline configurations, and hubs from one subgroup necessary to fulfill the centralized directed biogas scenario for stage 3 of the REPS, assuming the use of covered lagoons for biogas capture. The subgroups (i.e., Grp. 1, Grp. 2, etc.) are groupings of farms that would each have a single injection point to the existing natural gas pipeline, as shown by the stars in the figure.

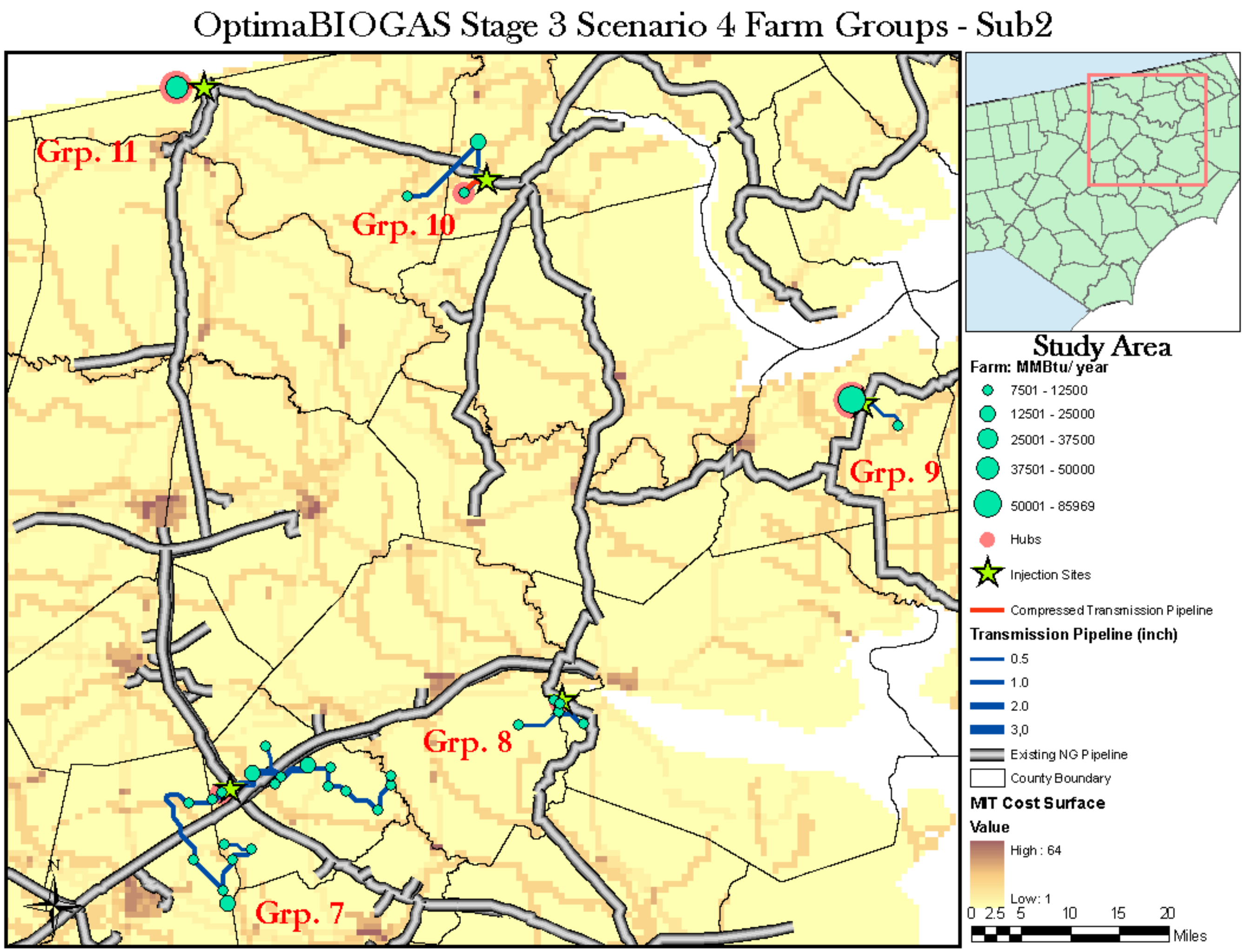


Figure A.9.3. Individual farms, farm clusters, pipeline configurations, and hubs from a second subgroup necessary to fulfill the centralized directed biogas scenario for stage 3 of the REPS, assuming the use of covered lagoons for biogas capture. The subgroups (i.e., Grp. 7, Grp. 8, etc.) are groupings of farms that would each have a single injection point to the existing natural gas pipeline, as shown by the stars in the figure.

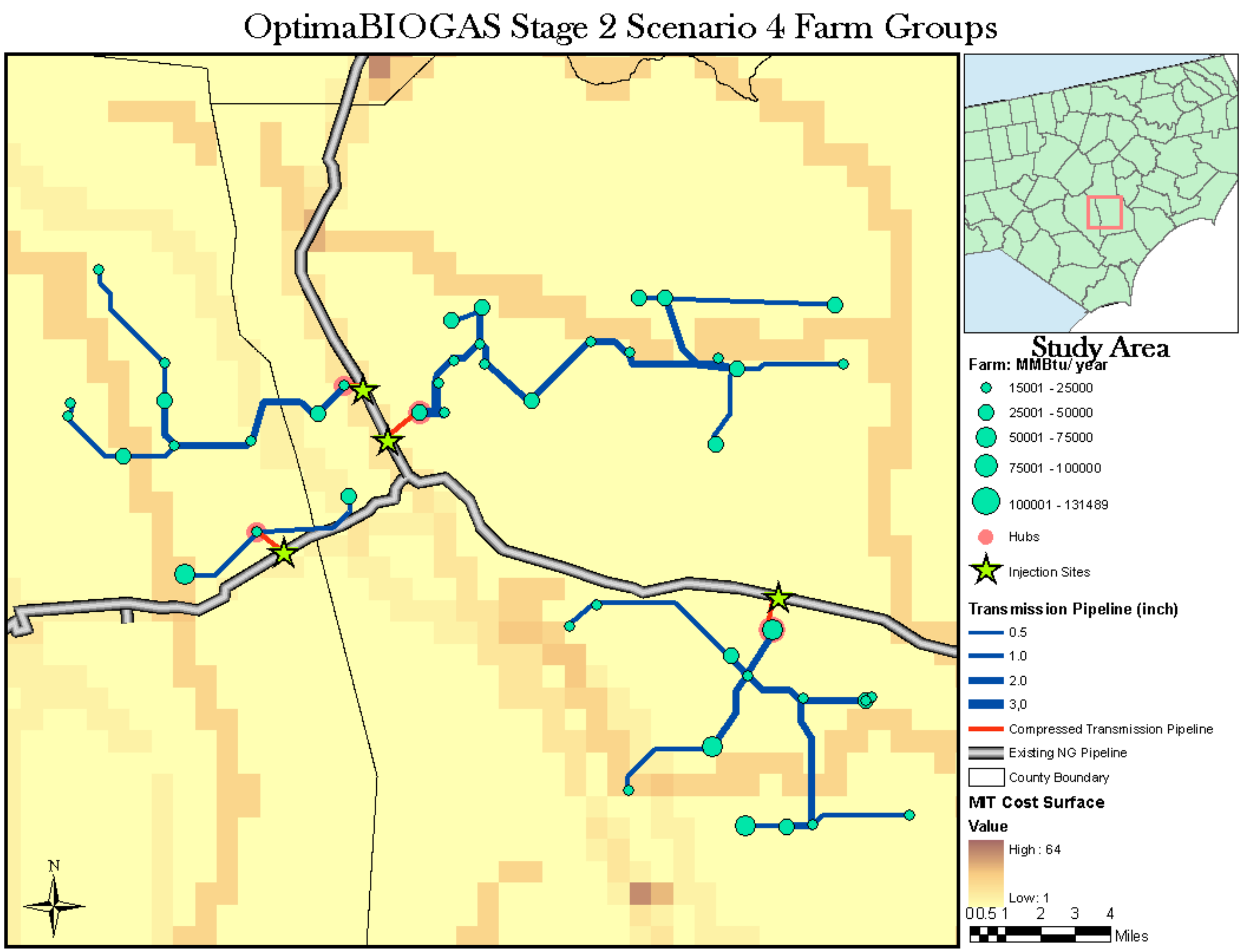


Figure A.9.4. Individual farms, farm clusters, pipeline configurations, and hubs necessary to fulfill the centralized directed biogas scenario for stage 2 of the REPS, assuming the use of mixed digesters for biogas capture.

OptimaBIOGAS Stage 3 Scenario 4 Farm Groups - Sub1

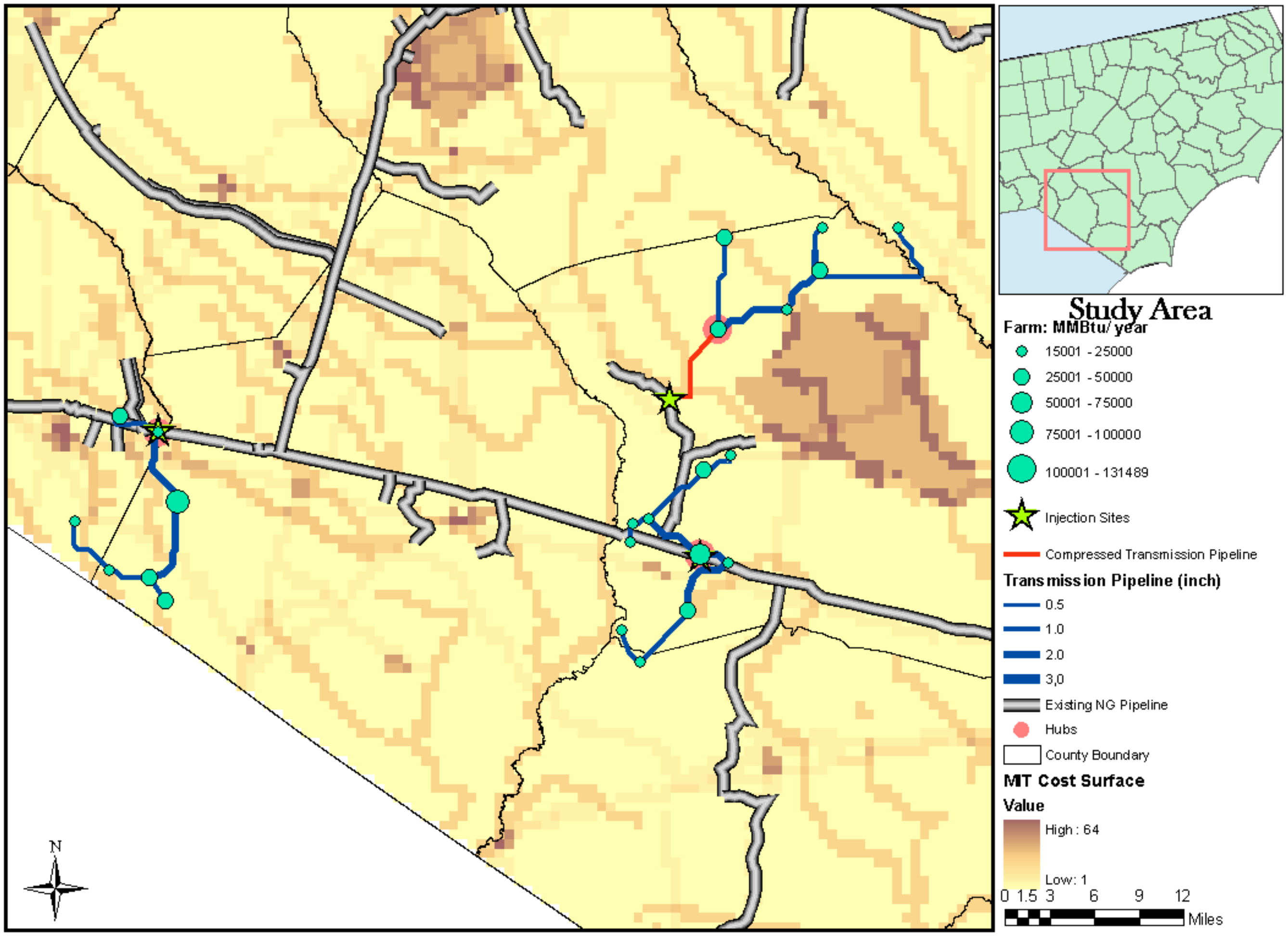


Figure A.9.5. Individual farms, farm clusters, pipeline configurations, and hubs from one subgroup necessary to fulfill the centralized directed biogas scenario for stage 3 of the REPS, assuming the use of mixed digesters for biogas capture.

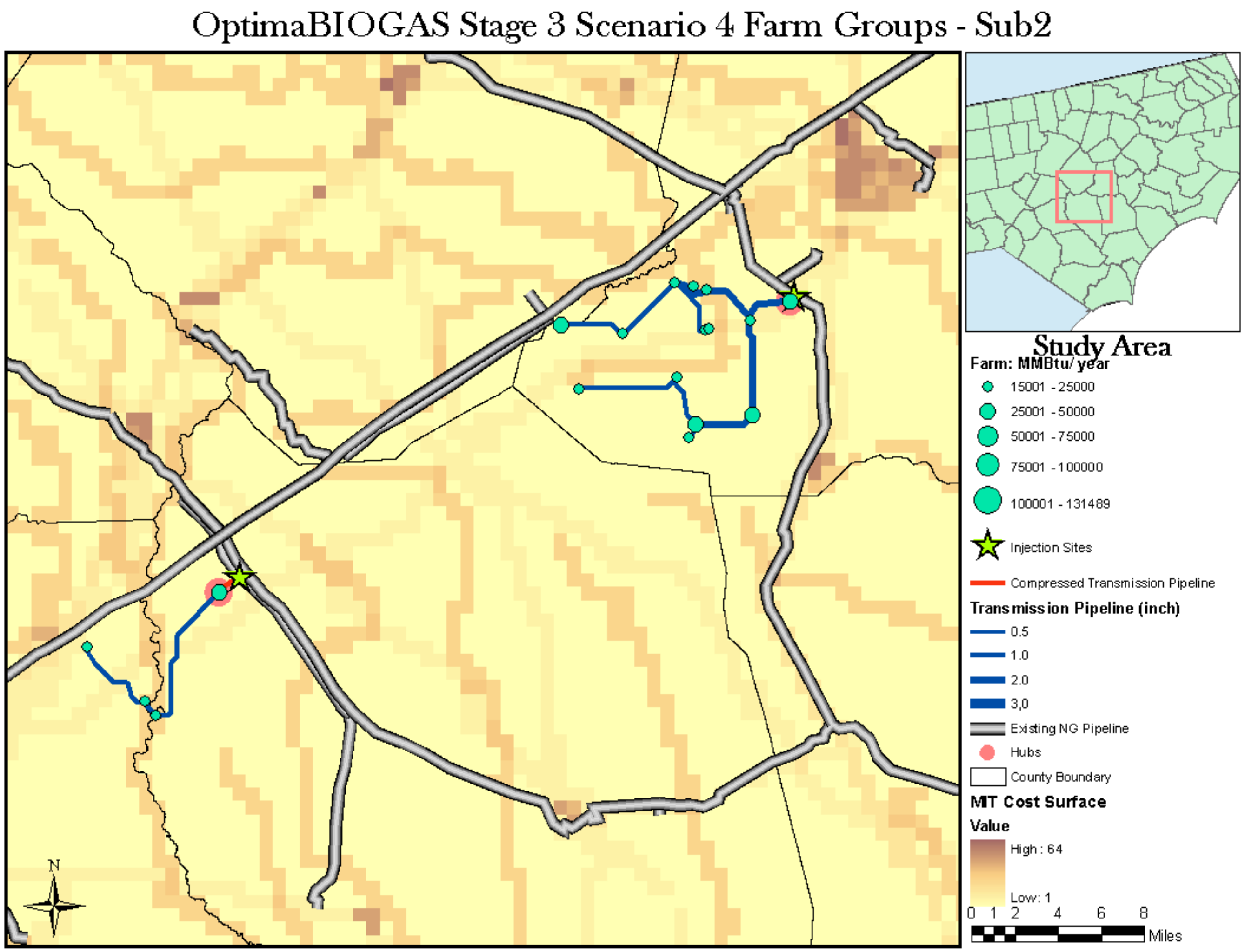


Figure A.9.6. Individual farms, farm clusters, pipeline configurations, and hubs from a second subgroup necessary to fulfill the centralized directed biogas scenario for stage 3 of the REPS, assuming the use of mixed digesters for biogas capture.

Appendix B. Cost Breakdown of Results

## *B.1.	Cost Components of Each Scenario Using Covered Lagoons*

Table B.1.1. Component costs of the biogas system for Scenario 1, for a system operated over 10 or 20 years. This table assumes that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 1		Biogas Capture	Biogas Conditioning	Electrical Generation	Grid Connection	Total cost ($)
Stage 1	10 years	$59,480,521	$36,335,505	$38,032,392	$12,900,000	$146,748,417
	20 years	$61,236,797	$40,913,232	$45,510,663	$12,900,000	$160,560,692
Stage 2	10 years	$77,097,482	$40,170,412	$43,079,412	$16,050,000	$176,397,306
	20 years	$78,906,826	$45,437,201	$51,544,908	$16,050,000	$191,938,934
Stage 3	10 years	$75,915,340	$38,195,344	$39,046,601	$13,650,000	$166,807,285
	20 years	$77,578,255	$43,070,802	$46,783,729	$13,650,000	$181,082,786
Total	10 years	$212,493,342	$114,701,262	$120,158,405	$42,600,000	$489,953,009
	20 years	$217,721,878	$129,421,234	$143,839,299	$42,600,000	$533,582,412

Table B.1.2. Component costs of the biogas system for Scenario 2, for a system operated over 10 or 20 years. The costs in this table assume the low-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 2		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$59,480,521	$55,642,660	$15,238,552	$90,561,092	$31,050,933	$36,238,661	$288,212,418
	20 years	$61,236,797	$66,257,074	$17,831,668	$117,692,308	$46,835,652	$54,660,558	$364,514,058
Stage 2	10 years	$77,097,482	$74,657,643	$21,406,876	$137,635,647	$47,191,516	$45,087,636	$403,076,799
	20 years	$78,906,826	$88,924,539	$25,047,610	$178,777,578	$71,181,289	$68,007,904	$510,845,746
Stage 3	10 years	$75,915,340	$65,150,151	$18,339,433	$107,812,508	$36,965,974	$38,345,559	$342,528,966
	20 years	$77,578,255	$77,590,807	$21,464,222	$140,085,002	$55,757,600	$57,838,498	$430,314,383
Total	10 years	$212,493,342	$195,450,454	$54,984,861	$336,009,247	$115,208,422	$119,671,856	$1,033,818,182
	20 years	$217,721,878	$232,772,420	$64,343,500	$436,554,888	$173,774,542	$180,506,959	$1,305,674,188

Table B.1.3. Component costs of the biogas system for Scenario 3, for a system operated over 10 or 20 years. The costs in this table assume the low-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 3		Biogas Capture	Biogas Conditioning	Pipeline Installation and Maintenance	Right of Way	Electrical Generation	Grid Connection	Total cost ($)
Stage 1	10 years	$59,480,521	$36,394,875	$7,963,525	$13,651,594	$29,737,822	$450,000	$147,678,337
	20 years	$61,236,797	$41,145,336	$10,582,918	$20,591,371	$35,691,519	$450,000	$169,697,942
Stage 2	10 years	$77,097,482	$40,170,412	$14,480,646	$24,823,649	$29,992,876	$1,350,000	$187,915,066
	20 years	$78,906,826	$45,456,438	$19,074,847	$37,442,734	$36,030,478	$1,350,000	$218,261,323
Stage 3	10 years	$75,915,340	$38,236,462	$13,863,114	$23,765,053	$30,752,032	$2,100,000	$184,632,001
	20 years	$77,578,255	$43,302,906	$18,254,993	$35,846,001	$36,964,585	$2,100,000	$214,046,740
Total	10 years	$212,493,342	$114,801,750	$36,307,285	$62,240,296	$90,482,730	$3,900,000	$520,225,403
	20 years	$217,721,878	$129,904,680	$47,912,757	$93,880,106	$108,686,582	$3,900,000	$602,006,004

Table B.1.4. Component costs of the biogas system for Scenario 4, for a system operated over 10 or 20 years. The costs in this table assume the low-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 4		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$59,480,521	$51,594,933	$2,830,619	$8,927,933	$13,416,053	$2,528,279	$138,778,338
	20 years	$61,236,797	$60,045,329	$3,466,370	$12,089,647	$20,236,093	$3,813,527	$160,887,764
Stage 2	10 years	$77,097,482	$56,810,963	$2,864,058	$18,791,441	$26,496,024	$2,949,658	$185,009,626
	20 years	$78,906,826	$65,649,105	$3,515,537	$24,961,817	$39,965,259	$4,449,115	$217,447,659
Stage 3	10 years	$75,915,340	$54,726,410	$3,430,584	$19,791,993	$27,308,373	$4,635,178	$185,807,878
	20 years	$77,578,255	$63,239,007	$4,113,340	$26,221,171	$41,190,565	$6,991,467	$219,333,805
Total	10 years	$212,493,342	$163,132,306	$9,125,261	$47,511,368	$67,220,450	$10,113,115	$509,595,841
	20 years	$217,721,878	$188,933,441	$11,095,247	$63,272,635	$101,391,918	$15,254,109	$597,669,229

Table B.1.5. Component costs of the biogas system for Scenario 2, for a system operated over 10 or 20 years. The costs in this table assume the high-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 2		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$59,480,521	55,642,660	15,238,552	595,096,379	150,068,644	$113,522,837	989,049,592
	20 years	$61,236,797	66,257,074	17,831,668	771,954,521	226,355,933	$171,232,090	1,314,868,084
Stage 2	10 years	$77,097,482	74,657,643	21,406,876	904,433,384	228,075,815	$141,243,529	1,446,914,729
	20 years	$78,906,826	88,924,539	25,047,610	1,173,131,785	26,507,531	$213,044,578	1,605,562,869
Stage 3	10 years	$75,915,340	65,150,151	18,339,433	708,459,138	178,655,939	$13,650,000	1,060,170,002
	20 years	$77,578,255	77,590,807	21,464,222	918,980,758	269,475,559	$120,123,002	1,485,212,603
Total	10 years	$212,493,342	195,450,454	54,984,861	$2,207,988,901	$556,800,398	$212,229,511	3,439,947,467
	20 years	$217,721,878	232,772,420	64,343,500	$2,864,067,065	$522,339,023	$504,399,670	4,405,643,555

Table B.1.6. Component costs of the biogas system for Scenario 3, for a system operated over 10 or 20 years. The costs in this table assume the high-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 3		Biogas Capture	Biogas Conditioning	Pipeline Installation and Maintenance	Right of Way	Electrical Generation	Grid Connection	Total cost ($)
Stage 1	10 years	$59,480,521	$36,394,875	$28,439,196	$65,977,926	$29,737,822	$450,000	$220,480,340
	20 years	$61,236,797	$41,145,336	$37,134,991	$99,517,758	$35,691,519	$450,000	$275,176,401
Stage 2	10 years	$77,097,482	$40,170,412	$51,713,019	$119,972,287	$29,992,876	$1,350,000	$320,296,076
	20 years	$78,906,826	$45,456,438	$67,356,375	$13,943,473	$36,030,478	$1,350,000	$243,043,590
Stage 3	10 years	$75,915,340	$38,236,462	$49,507,700	$114,856,108	$30,752,032	$2,100,000	$311,367,642
	20 years	$77,578,255	$43,302,906	$64,477,539	$173,243,129	$36,964,585	$2,100,000	$397,666,415
Total	10 years	$212,493,342	$114,801,750	$129,659,915	$300,806,320	$90,482,730	$3,900,000	$852,144,058
	20 years	$217,721,878	$129,904,680	$168,968,905	$286,704,360	$108,686,582	$3,900,000	$915,886,406

Table B.1.7. Component costs of the biogas system for Scenario 4, for a system operated over 10 or 20 years. The costs in this table assume the high-end pipeline cost estimates and that covered lagoons are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 4		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$59,480,521	$51,594,933	$2,830,619	$36,015,345	$64,839,560	$7,920,198	$222,681,176
	20 years	$61,236,797	$60,045,329	$3,466,370	$47,215,574	$97,800,704	$11,946,425	$281,711,200
Stage 2	10 years	$77,097,482	$56,810,963	$2,864,058	$79,615,109	$128,054,846	$9,240,231	$353,682,689
	20 years	$78,906,826	$65,649,105	$3,515,537	$103,835,642	$14,882,848	$13,937,496	$280,727,453
Stage 3	10 years	$75,915,340	$54,726,410	$3,430,584	$85,163,548	$131,980,915	$14,520,363	$365,737,159
	20 years	$77,578,255	$63,239,007	$4,113,340	$110,992,522	$199,073,320	$21,901,779	$476,898,224
Total	10 years	$212,493,342	$163,132,306	$9,125,261	$200,794,001	$324,875,321	$31,680,792	$942,101,024
	20 years	$217,721,878	$188,933,441	$11,095,247	$262,043,737	$311,756,873	$47,785,700	$1,039,336,877

B.2. Cost Components of Each Scenario Using Mixed Digesters

Table B.2.1. Component costs of the biogas system for Scenario 1, for a system operated over 10 or 20 years. The costs in this table assume that mixed digesters are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 1		Biogas Capture	Biogas Conditioning	Electrical Generation	Grid Connection	Total cost ($)
Stage 1	10 years	$43,502,031	$24,883,101	$31,782,412	$5,850,000	$106,017,543
	20 years	$46,626,922	$27,621,254	$37,825,369	$5,850,000	$117,923,546
Stage 2	10 years	$44,483,231	$25,611,132	$32,155,983	$6,900,000	$109,150,345
	20 years	$47,533,132	$28,429,620	$38,209,651	$6,900,000	$121,072,403
Stage 3	10 years	$42,373,803	$25,545,367	$32,790,614	$6,300,000	$107,009,785
	20 years	$45,934,604	$28,380,323	$39,015,664	$6,300,000	$119,630,590
Total	10 years	$130,359,065	$76,039,600	$96,729,009	$19,050,000	$322,177,674
	20 years	$140,094,658	$84,431,197	$115,050,684	$19,050,000	$358,626,539

Table B.2.2. Component costs of the biogas system for Scenario 4, for a system operated over 10 or 20 years. The costs in this table assume the low-end pipeline cost estimates and that mixed digesters are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 4		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$24,757,190	$38,764,576	$2,147,884	$3,804,487	$5,671,721	$842,760	$75,988,617
	20 years	$27,882,081	$45,589,458	$2,727,597	$5,445,756	$8,554,936	$1,271,176	$91,471,005
Stage 2	10 years	$24,163,074	$39,380,312	$2,631,641	$4,821,949	$5,671,721	$1,685,519	$78,354,216
	20 years	$27,212,975	$45,249,204	$3,141,795	$6,846,711	$8,554,936	$2,542,352	$93,547,972
Stage 3	10 years	$28,210,711	$40,750,199	$2,493,479	$8,504,714	$11,744,681	$1,685,519	$93,389,302
	20 years	$31,771,511	$47,475,294	$3,201,852	$11,584,255	$17,715,082	$2,542,352	$114,290,346
Total	10 years	$77,130,974	$118,895,086	$7,273,003	$17,131,150	$23,088,123	$4,213,798	$247,732,135
	20 years	$86,866,568	$138,313,955	$9,071,245	$23,876,721	$34,824,955	$6,355,879	$299,309,322

Table B.2.3. Component costs of the biogas system for Scenario 4, for a system operated over 10 or 20 years. The costs in this table assume the high-end pipeline cost estimates and that mixed digesters are employed to capture the biogas. In each column, capital and O&M costs are combined.

Scenario 4		Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Right of Way	Pipeline Injection Cost	Total cost ($)
Stage 1	10 years	$24,757,190	$38,764,576	$2,147,884	$15,446,166	$27,411,334	$2,640,066	$111,167,215
	20 years	$27,882,081	$45,589,458	$2,727,597	$20,542,244	$41,345,866	$3,982,142	$142,069,388
Stage 2	10 years	$24,163,074	$39,380,312	$2,631,641	$19,824,009	$27,411,334	$5,280,132	$118,690,501
	20 years	$27,212,975	$45,249,204	$3,141,795	$26,300,812	$41,345,866	$7,964,283	$151,214,935
Stage 3	10 years	$28,210,711	$40,750,199	$2,493,479	$36,572,913	$56,761,851	$5,280,132	$170,069,284
	20 years	$31,771,511	$47,475,294	$3,201,852	$47,982,031	$85,616,698	$7,964,283	$224,011,670
Total	10 years	$77,130,974	$118,895,086	$7,273,003	$71,843,089	$111,584,519	$13,200,330	$399,927,001
	20 years	$86,866,568	$138,313,955	$9,071,245	$94,825,087	$168,308,430	$19,910,708	$517,295,993

B.3. Cost Structure of Scenario 4 Subgroups

Table B.3.1. Component costs for subgroups of Scenario 4. Costs in this table assume the low-end pipeline cost estimates, that covered lagoons are used for biogas capture, and that the system will be operated for 20 years. In each column, capital and O&M costs are combined.

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (MMBtu/year)
1a	34	$24,260,312	$27,053,283	$1,579,223	$4,235,075	$8,866,349	$744,478	$66,738,719	$16,595,243	530,992
1b	3	$2,260,670	$2,940,000	$249,952	$650,854	$1,004,383	$744,478	$7,850,336	$1,521,984	48,369
1c	11	$8,054,508	$7,473,214	$403,508	$1,684,696	$3,618,041	$744,478	$21,978,445	$3,300,171	117,400
1d	18	$12,296,838	$12,102,777	$653,460	$2,214,800	$4,657,079	$744,478	$32,669,432	$6,388,891	218,100
1e	5	$3,053,379	$3,485,817	$249,952	$669,337	$1,153,593	$744,478	$9,356,555	$1,344,549	49,274
1f	15	$9,121,243	$11,161,733	$653,460	$1,953,832	$4,057,345	$744,478	$27,692,091	$6,631,242	216,116
2a	7	$12,572,425	$6,815,102	$403,508	$3,951,161	5343045.671	$744,478	$29,829,720	$4,982,989	150,501
2b	12	$8,200,493	$7,906,736	$403,508	$3,398,635	$5,814,382	$744,478	$26,468,232	$3,265,619	119,276
2c	24	$14,857,717	$14,860,729	$789,611	$3,309,817	$7,440,758	$744,478	$42,003,111	$6,378,717	234,543
2d	15	$10,718,462	$9,528,529	$653,460	$2,650,855	$6,048,285	$744,478	$30,344,069	$5,282,817	180,665
2e	31	$20,939,023	$19,175,273	$789,611	$7,471,732	$14,400,498	$744,478	$63,520,615	$8,852,457	319,075

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (MMBtu/year)
2f	9	$5,750,699	$5,927,799	$403,508	$2,090,750	$4,466,156	$744,478	$19,383,391	$2,269,460	84,731
2g	9	$4,940,302	$5,927,799	$403,508	$1,139,253	$2,615,558	$744,478	$15,770,898	$2,340,883	86,609
3a	11	$7,879,859	$7,832,736	$403,508	$3,273,790	$6,196,681	$744,478	$26,331,051	$3,541,744	123,751
3b	21	$19,363,043	$14,987,102	$789,611	$4,467,986	10435267.07	$744,478	$50,787,487	$7,918,193	266,661
3c	12	$9,137,825	$7,906,736	$403,508	$4,901,590	$7,700,360	$744,478	$30,794,497	$3,972,183	137,852
3d	9	$8,017,193	$7,929,373	$403,508	$2,250,728	$5,211,481	$744,478	$24,556,761	$4,763,579	150,303
3e	3	$4,308,270	$2,618,773	$249,952	$1,014,821	$1,343,068	$744,478	$10,279,361	$1,136,227	38,227
3f	4	$3,583,108	$3,760,189	$403,508	$1,126,875	$1,988,769	$744,478	$11,606,927	$1,818,970	58,962
3g	20	$16,038,347	$11,374,913	$653,460	$4,108,559	$9,080,074	$744,478	$41,999,830	$5,040,324	188,216
3h	5	$4,068,153	$3,485,817	$249,952	$736,947	$1,457,351	$744,478	$10,742,697	$1,232,277	46,323
3i	2	$1,098,799	$2,893,145	$403,508	$737,245	$1,077,676	$744,478	$6,954,850	$2,975,610	83,800
3j	3	$4,003,076	$2,940,000	$249,952	$1,825,174	$2,656,276	$744,478	$12,418,955	$1,192,627	39,710
3k	1	$925,906	$1,751,729	$249,952	$847,437	$395,872	$744,478	$4,915,373	$1,518,573	42,709

Table B.3.2. Component costs for subgroups of Scenario 4. Costs in this table assume the high-end pipeline cost estimates, that covered lagoons are used for biogas capture, and that the system will be operated for 20 years. In each column, capital and O&M costs are combined.

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (MMBtu/year)
1a	34	$24,260,312	$27,053,283	$1,579,223	$16,769,916	$42,850,916	$2,332,185	$114,845,834	$16,595,243	530992.55
1b	3	$2,260,670	$2,940,000	$249,952	$3,152,393	$4,854,166	$2,332,185	$15,789,365	$1,521,984	48369.18
1c	11	$8,054,508	$7,473,214	$403,508	$6,524,824	$17,485,931	$2,332,185	$42,274,169	$3,300,171	117400.08
1d	18	$12,296,838	$12,102,777	$653,460	$8,737,529	$22,507,587	$2,332,185	$58,630,376	$6,388,891	218100.2
1e	5	$3,053,379	$3,485,817	$249,952	$3,048,136	$5,575,294	$2,332,185	$17,744,762	$1,344,549	49274.75
1f	15	$9,121,243	$11,161,733	$653,460	$7,789,877	$19,609,082	$2,332,185	$50,667,579	$6,631,242	216116.08
2a	7	$12,572,425	$6,815,102	$403,508	$20,348,491	25822851.34	$2,332,185	$68,294,563	$4,982,989	150501.2
2b	12	$8,200,493	$7,906,736	$403,508	$15,546,495	$28,100,811	$2,332,185	$62,490,227	$3,265,619	119276.9
2c	24	$14,857,717	$14,860,729	$789,611	$12,284,843	$35,961,061	$2,332,185	$81,086,147	$6,378,717	234543.93
2d	15	$10,718,462	$9,528,529	$653,460	$9,696,222	$29,231,263	$2,332,185	$62,160,121	$5,282,817	180665.45
2e	31	$20,939,023	$19,175,273	$789,611	$31,580,477	$69,597,371	$2,332,185	$144,413,939	$8,852,457	319075.98
2f	9	$5,750,699	$5,927,799	$403,508	$8,135,883	$21,584,858	$2,332,185	$44,134,933	$2,269,460	84731.85

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (MMBtu/year)
2g	9	$4,940,302	$5,927,799	$403,508	$4,141,116	$12,640,948	$2,332,185	$30,385,858	$2,340,883	86609.6
3a	11	$7,879,859	$7,832,736	$403,508	$14,018,629	$29,948,455	$2,332,185	$62,415,372	$3,541,744	123751.13
3b	21	$19,363,043	$14,987,102	$789,611	$15,955,991	50433473.12	$2,332,185	$103,861,405	$7,918,193	266661.78
3c	12	$9,137,825	$7,906,736	$403,508	$23,521,824	$37,215,710	$2,332,185	$80,517,789	$3,972,183	137852.75
3d	9	$8,017,193	$7,929,373	$403,508	$8,110,398	$25,186,999	$2,332,185	$51,979,656	$4,763,579	150303.25
3e	3	$4,308,270	$2,618,773	$249,952	$5,273,290	$6,491,026	$2,332,185	$21,273,495	$1,136,227	38227.48
3f	4	$3,583,108	$3,760,189	$403,508	$5,056,903	$9,611,686	$2,332,185	$24,747,579	$1,818,970	58962.28
3g	20	$16,038,347	$11,374,913	$653,460	$15,500,486	$43,883,847	$2,332,185	$89,783,237	$5,040,324	188216.23
3h	5	$4,068,153	$3,485,817	$249,952	$3,055,396	$7,043,351	$2,332,185	$20,234,854	$1,232,277	46323.08
3i	2	$1,098,799	$2,893,145	$403,508	$3,667,204	$5,208,389	$2,332,185	$15,603,230	$2,975,610	83800.38
3j	3	$4,003,076	$2,940,000	$249,952	$9,097,560	$12,837,739	$2,332,185	$31,460,510	$1,192,627	39710.25
3k	1	$925,906	$1,751,729	$249,952	$5,568,693	$1,913,241	$2,332,185	$12,741,705	$1,518,573	42709.1

Table B.3.3. Component costs for subgroups of Scenario 4. Costs in this table assume the low-end pipeline cost estimates, that mixed digesters are used for biogas capture, and that the system will be operated for 20 years. In each column, capital and O&M costs are combined.

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (mmBTU/year)
1a	34	$27,008,191	$44,113,032	$2,618,786	$3,672,526	$6,295,683	$546,429	$84,254,648	$36,792,693	1,061,992
1b	5	$2,462,390	$4,836,165	$403,508	$456,684	$782,877	$546,429	$9,488,054	$3,218,938	98,553
2a	10	$4,945,950	$4,402,643	$403,508	$380,350	$652,020	$546,429	$11,330,900	$2,620,243	96,739
2b	18	$11,001,653	$8,645,828	$653,460	$1,080,791	$1,852,763	$546,429	$23,780,924	$5,622,620	197,955
2c	18	$11,001,653	$18,403,519	$1,193,120	$1,937,142	$3,320,776	$546,429	$36,402,639	$14,684,949	436,207
2d	15	$10,398,707	$16,698,906	$1,193,120	$1,728,573	$2,963,233	$546,429	$33,528,968	$14,241,600	416,195
3a	7	$8,973,795	$11,639,150	$789,611	$1,899,285	$3,255,879	$546,429	$27,104,150	$10,707,593	301,003
3b	10	$7,869,928	$11,220,335	$789,611	$1,885,523	$3,232,287	$546,429	$25,544,115	$8,672,901	255,866
3c	7	$5,451,881	$10,685,668	$789,611	$1,624,823	$2,785,377	$546,429	$21,883,790	$8,343,161	238,841
3d	4	$2,946,401	$4,995,576	$403,508	$794,164	$1,361,408	$546,429	$11,047,486	$3,390,497	100,278
3e	14	$8,339,596	$12,197,085	$789,611	$2,143,540	$3,674,595	$546,429	$27,690,857	$9,044,053	276,765

Table B.3.4. Component costs for subgroups of Scenario 4. Costs in this table assume the high-end pipeline cost estimates, that mixed digesters are used for biogas capture, and that the system will be operated for 20 years. In each column, capital and O&M costs are combined.

Subgroup	# of Farms	Biogas Capture	Biogas Conditioning	Biogas Compression	Pipeline Installation and Maintenance	Pipeline Right of Way	Pipeline Injection	Total Costs	Carbon Offset Revenue	Biogas Productions (MMBtu/year)
1a	34	$27,008,191	$44,113,032	$2,618,786	$13,115,258	$30,426,934	$1,711,769	$118,993,970	$36,792,693	1,061,992
1b	5	$2,462,390	$4,836,165	$403,508	$1,630,901	$3,783,633	$1,711,769	$14,828,366	$3,218,938	98,553
2a	10	$4,945,950	$4,402,643	$403,508	$1,358,298	$3,151,202	$1,711,769	$15,973,370	$2,620,243	96,739
2b	18	$11,001,653	$8,645,828	$653,460	$3,859,703	$8,954,374	$1,711,769	$34,826,786	$5,622,620	197,955
2c	18	$11,001,653	$18,403,519	$1,193,120	$6,917,887	$16,049,253	$1,711,769	$55,277,201	$14,684,949	436,207
2d	15	$10,398,707	$16,698,906	$1,193,120	$6,173,049	$14,321,255	$1,711,769	$50,496,805	$14,241,600	416,195
3a	7	$8,973,795	$11,639,150	$789,611	$6,782,693	$15,735,608	$1,711,769	$45,632,627	$10,707,593	301,003
3b	10	$7,869,928	$11,220,335	$789,611	$6,733,547	$15,621,589	$1,711,769	$43,946,780	$8,672,901	255,866
3c	7	$5,451,881	$10,685,668	$789,611	$5,802,538	$13,461,682	$1,711,769	$37,903,149	$8,343,161	238,841
3d	4	$2,946,401	$4,995,576	$403,508	$2,836,106	$6,579,664	$1,711,769	$19,473,023	$3,390,497	100,278
3e	14	$8,339,596	$12,197,085	$789,611	$7,654,970	$17,759,259	$1,711,769	$48,452,290	$9,044,053	276,765

Appendix C. Carbon Offset Overview and Calculation of Carbon Offsets and Pricing for the Swine Biogas Analysis

Carbon offset credits or "carbon offsets" or "carbon credits" are voluntary and verifiable reductions in greenhouse gas (GHG) emissions. The credits generated by carbon offset projects can be sold to other parties, who can use them, for example, to comply with California's cap-and-trade regulations on GHG emissions.[34] Parties that have made voluntary commitments to cutting their GHG emissions can also purchase carbon offsets to apply against their voluntary commitments.

Carbon offsets are measured in metric ton equivalents to carbon dioxide ($MTCO_2e$). Biogas projects at swine farms are particularly promising for generating carbon offsets because the result in the destruction of methane, which is 21 times more potent than carbon dioxide in the atmosphere. Thus, for every metric ton of methane destroyed, 21 carbon offsets will be earned.

To estimate the revenue from carbon offsets, the California Air Resource Board (CARB) Compliance Offset Protocol for Livestock Projects was used to determine that 1 mmBTU of biogas equals approximately 0.359 metric tons carbon dioxide equivalent ($MTCO_2e$). In other words, for each mmBTU of biogas destroyed, the project will earn 0.359 carbon credits. This calculation takes into account the requirement that each farm must model its baseline emissions (i.e., the amount of GHGs the farm would emit in the absence of the project) and is not allowed to earn carbon credits in excess of that baseline.[35] For pricing purposes, the present analysis assumes sale of the carbon offsets in the California market using a static carbon price of $10 per credit, which conservatively estimates the revenue considering that the price of carbon is projected to rise significantly in the California carbon market as the California cap-and-trade market matures and emission caps become more stringent. Adding to the conservative nature of the carbon revenue estimates, the analysis includes the purchase of a backup flare at each farm, at a cost of $15,000, and an annual cost of $10,000 to cover the costs of required monitoring and third-party verification,[36] which normally occurs every two years. Per the requirements of the California carbon offset protocol, projects can generate carbon credits for up to 20 years.

The CARB Compliance Protocol for Livestock Projects[37] contains the procedure for determining the number of carbon credits a project will earn. This procedure includes a series of equations that use the farm's swine population to model the farm's baseline methane emissions, or the emissions of methane

[34] For more information on generating carbon offsets from swine farm projects for the California carbon market, see http://www.arb.ca.gov/cc/capandtrade/protocols/livestock/livestock.htm.

[35] In some cases, highly efficient digesters can produce more methane than would have been generated in the baseline or business-as-usual scenario. In these cases, the projects will only earn credit for the baseline emissions because those are the emissions that would have occurred in the absence of the project.

[36] Because carbon offsets are generated when methane is destroyed, it does not matter if the methane is destroyed through the process of electricity generation or if it is simply burned in a flare. The flare is not necessarily required for a carbon project, but is included as a backup in the event that the electricity generation system is down for maintenance or repair. The carbon offsets can be counted from North Carolina swine waste-to-energy projects because the renewable energy does not carry any additional environmental attributes, including carbon, that results from generating renewable energy. See NCGS §62-133.8, available at http://www.ncleg.net/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-133.8.html.

[37] California Environmental Protection Agency, Air Resources Board. Compliance Offset Protocol Livestock Projects, 2011, available at http://www.arb.ca.gov/regact/2010/capandtrade10/coplivestockfin.pdf.

that would have occurred in an uncovered lagoon in the absence of a biogas (i.e., methane) collection project.[38]

In addition to determining the farm's baseline methane emissions, the actual amount of methane destroyed as a result of the project must be measured. Projects earn carbon offset credits based on the amount of methane they actually destroy, up to and limited by the baseline emissions established for the farm. In other words, if the amount of methane a project destroys in a given year is greater than the modeled baseline, then the number of credits the project receives will be based on – or is limited to –the modeled baseline. Thus, the project can never earn more carbon offsets than the farm's established emissions baseline, otherwise the project could result in increased emissions beyond business-as-usual. The purpose of this approach is to protect against an unintended increase in methane in the atmosphere as a result of a highly efficient methane capture and destruction device, such as a highly efficient anaerobic digester which is far superior to a traditional open air lagoon at producing methane. Thus, if a project employs an anaerobic digester that generates more methane per unit of swine waste than would have been generated by the replaced open-air lagoon, then the project will only receive credit for the baseline methane emissions calculated for the operation.

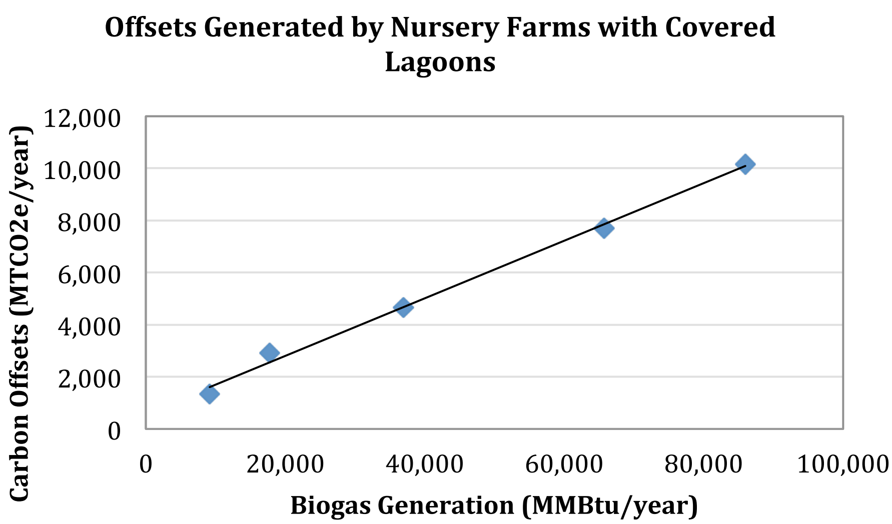
The modeling team used biogas production to extrapolate potential carbon offsets. Specifically, to estimate the carbon offset generation potential for the North Carolina Swine Biogas Analysis, a sample of twenty-four swine farms, with swine populations ranging from 1,200 to 70,000 head, was selected from the farms identified in the analysis, and specific information on the type and number of swine at these farms was used along with the equations in the CARB protocol to estimate the number of carbon credits capable of being earned by each farm (the emissions baseline). The number of credits each farm would generate was then plotted against the amount of biogas the farms were modeled to generate (MMBtu/year). The relationship between the two variables was nearly perfect (Figure 1-4, below). Simple linear regression methods were then used to determine an equation to estimate the carbon offset generation at all other swine farms selected in the study (Table 1). The relationships differed based on whether the farms were feeder-to-finish or nursery farms, and on whether the farms used covered lagoons or mixed digesters.

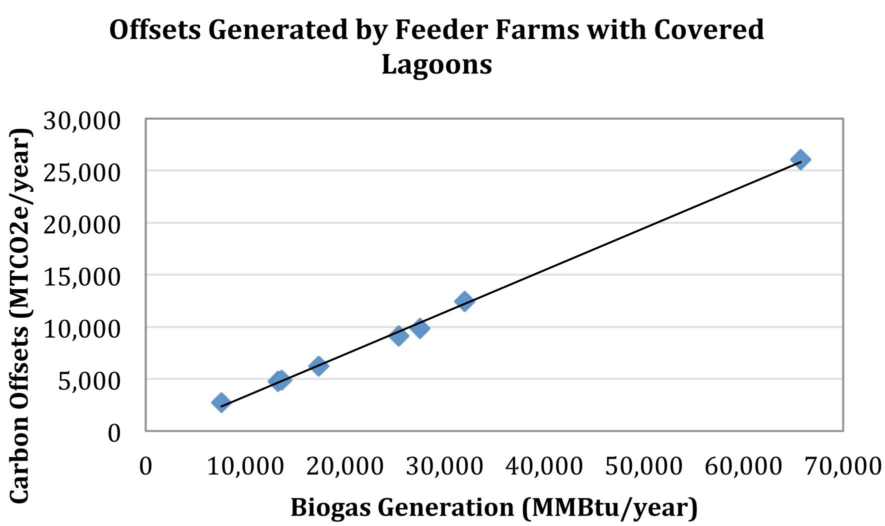
Note that many factors affect carbon offset generation for any individual project, therefore actual generation rates may vary. Furthermore, carbon offset projects must account for any coincidental GHG emissions they create, such as those emissions from fuel or electricity use to operate pumps or other equipment. An exception to the requirement to deduct electricity use is allowed where projects generate electricity in excess of the electricity they consume, in which case GHG emissions from coincidental electricity use need not be deducted. However, it is unclear from the CARB protocol whether this applies to pipeline injection (i.e., "directed biogas") projects where electricity is generated off-site.

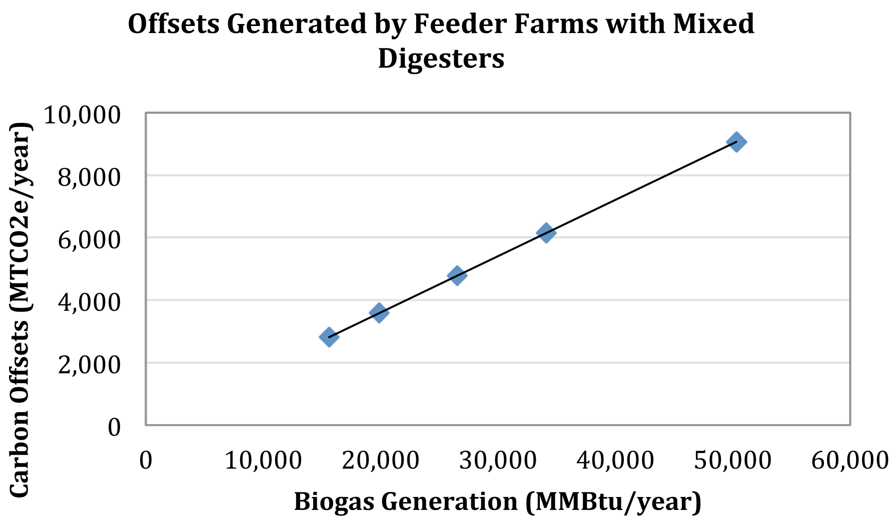
[38] *See id.* at 12-18.

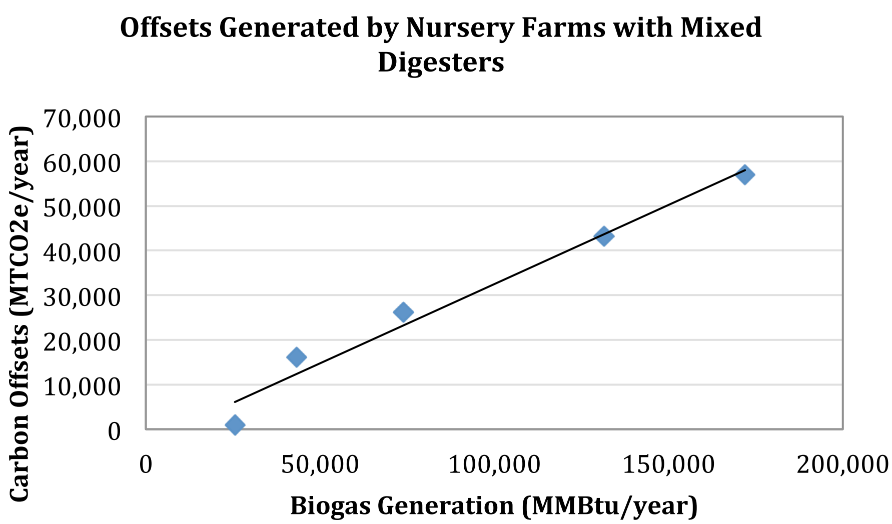
Table 1. Relationship between Biogas Generation (MMBtu/year) and Carbon Offset Generation ($MTCO_2e$/year)

Biogas Capture System	Farm Type	Relationship between Biogas Generation and Carbon Offsets
Covered Lagoons	Feeder-to-finish	$MTCO_2e$/year = 0.359 x MMBtu/year
	Nursery	$MTCO_2e$/year = (0.1105 x MMBtu/year) + 594.01
Mixed Digesters	Feeder-to-finish	$MTCO_2e$/year = 0.1802 x MMBtu/year + 0.29
	Nursery	$MTCO_2e$/year = (0.3545 x MMBtu/year) + 2,962.9






Offsets Generated by Feeder Farms with Mixed Digesters
10,000
8,000
6,000
4,000
2,000
0
0
10,000
20,000
30,000
40,000
50,000
60,000
Carbon Offsets (MTCO2e/year)
Biogas Generation (MMBtu/year)


Offsets Generated by Nursery Farms with Mixed Digesters
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
0
50,000
100,000
150,000
200,000
Carbon Offsets (MTCO2e/year)
Biogas Generation (MMBtu/year)

Appendix D. Equipment Configuration Optimization

D.1. Mathematical Modeling

The core engine of OptimaBIOGAS is a cost minimization optimization formulated as a mixed-integer programming (MIP) model. The model is an extension of the basic assembly problem discussed by McCarl et al. (McCarl & Spreen, 2003). The model determines the lowest cost in building infrastructure in capturing biogas and generating electricity.

Mathematical Model: Scenarios 1 & 3

Scenario 1

In Scenario 1, the biogas is collected in the farms, and the raw biogas is processed using proper conditioning units to remove water, impurities, or both before being used for electricity generation. Once the electricity is generated, the transformer is used to transform and direct the electricity back to the power grid.

As a result, the conditioning unit, the generator, and the transformer are the three major components in the Scenario 1 model. The goal of the objective function is to minimize the capital and O&M cost over the operating period and therefore identify the most optimal equipment configurations for individual farms. The model can pair the conditioning units with proper types of generators. For example, the micro-turbine generators can only be used with light conditioning units (remove water), and the combustion engine electric generator can only be used with heavy conditioning units (remove water, CO_2, H_2S, and other impurities).

Sets:

F Swine farms

$Cond_i$ Biogas conditioning equipment model i

Gen_j Biogas electric generator model j

$Trans_k$ Electricity transformer model k

Scalars:

r Discount rate (7%)

ConversionF To convert biogas production rate (MMBtu/year) into biogas flow rate (CFH) (0.2021)

CondLossRate Percentage of biogas loss during conditioning. 0.03 for light conditioning (water removal) and 0.43 for heavy conditioning (purification).

Parameters:

$GCapture_F$	Annual biogas captured on farm F (MMBtu/year)
$CondCapacity_i$	Capacity of conditioning equipment model i (CFH)
$GenCapacity_j$	Fuel consumption capacity of electric generator model j (CFH)
$GenElectricity_j$	Electricity generation of electric generator model j (kW)
$TransCapacity_k$	Capacity of electricity transformer model k (kW)
$CondCapitalCost_i$	Capital cost of conditioning equipment model i ($)
$GenCapitalCost_j$	Capital cost of electric generator model j ($)
$TransCapitalCost_k$	Capital cost of electricity transformer model k ($)
$CondOMCost_i$	Annual operations and maintenance cost of conditioning equipment model i ($)
$GenOMCost_j$	Annual operations and maintenance cost of electric generator model j ($)
$TransOMCost_k$	Annual operations and maintenance cost of electricity transformer model k ($)
t	Years of operation (years)
CDF_t	Cumulative discount factor for t years of operations (1/r -1/r(1+r)^t)

Integer Variables:

$XCond_{F,i}$	Number of conditioning equipment model i required on farm F
$XGen_{F,j}$	Number of electric generator model j required on farm F
$XTrans_{F,k}$	Number of electric transformer type k required on farm F

Objective function and constraints:

$$MINIMIZING \sum_{F,i} (XCond_{F,i} * CondCapitalCost_i + XCond_{F,i} * CondOMCost_i * CDF_t)$$
$$+\sum_{F,j} (XGen_{F,i} * GenCapitalCost_j + XGen_{F,j} * GenOMCost_j * CDF_t)$$
$$+\sum_{F,k} (XTrans_{F,k} * TransCapitalCost_j + XTrans_{F,k} * TransOMCost_k * CDF_t)$$

$$S.T.$$
$$\sum_i (XCond_{F,i} * CondCapacity_i) \geq GCapture_F * ConversionF$$
$$\sum_j (XGen_{F,j} * GenCapacity_j) \geq GCapture_F * ConversionF * (1 - CondLossRate)$$
$$\sum_k (XTrans_{F,k} * TransCapacity_k) \geq \sum_j (XGen_{F,j} * GenElectricity_j)$$
$$XCond_{F,i}, XGen_{F,j}, XTrans_{F,k} \geq 0$$

Scenario 3

In Scenario 3, the biogas is first collected in the individual farms and transported to a hub farm for electricity generation. At the level of individual farms, the raw biogas is subjected to light conditioning to remove the water before transporting to the hub farm. At the hub farm level, the collected biogas is used for electricity generation through either micro-turbines or combustion engine electric generator. Further heavy conditioning is required for the combustion engine generator. Last, the electricity is directed back to the power grid through an interconnection.

The optimization is separated into farm and hub levels. At the farm level, water removal unit is the only component. At the hub level, heavy conditioning (if a combustion engine is chosen), generators, and transformers are the major components.

Optimization at **individual farms** level:

Sets:

F	Swine farms
WR_l	Water removal conditioner type l

Parameters:

$GCapture_F$	Annual biogas captured on farm F (mmBTU/year)
$WRCapacity_l$	Capacity of water removal conditioner type l (CFH)
$WRCapitalCost_l$	Capital cost of water removal conditioner type l ($)
$WROMCost_l$	Annual operations and maintenance cost of water removal conditioner type i ($)
t	Years of operation (years)
CDF_t	Cumulative discount factor for t years of operations (1/r -1/r(1+r)^t)

Scalars:

r	Discount rate (7%)
ConversionF	To convert biogas production rate (mmbtu/year) into biogas flow rate (CFH) (0.2021)

Integer Variables:

$XWR_{F,l}$	Number of water removal conditioner type l required on farm F

Objective function and constraints:

$$MINIMIZING \sum_{F,l} (XWR_{F,l} * WRCapitalCost_l + XWR_{F,l} * WROMCost_l * CDF_t)$$

$$S.T.$$

$$\sum_{l} (XWR_{F,l} * WRCapacity_l) \geq GCapture_F * ConversionF$$

$$XWR_{F,l} \geq 0$$

<u>Optimization at **hub** level:</u>

Sets:

H	Hub farm

F Swine farms

$Cond_i$ Biogas conditioning equipment model i

Gen_j Biogas electric generator model j

$Trans_k$ Electricity transformer model k

Scalars:

r Discount rate (7%)

ConversionF To convert biogas production rate (MMBtu/year) into biogas flow rate (CFH) (0.2021)

WRLossRate Methane loss rate through water removal (3%)

CondLossRate Percentage of biogas loss during conditioning. Equal to 0% when model selects micro-turbines; equal to 43% when model selects combustion engine generator

Parameters:

$GCapture_F$ Annual biogas captured on farm F (MMBtu/year)

$CondCapacity_i$ Capacity of conditioning equipment model i (CFH)

$GenCapacity_j$ Fuel consumption capacity of electric generator model j (CFH)

$GenElectricity_j$ Electricity generation of electric generator model j (kW)

$TransCapacity_k$ Capacity of electricity transformer model k (kW)

$CondCapitalCost_i$ Capital cost of conditioning equipment model i ($)

$GenCapitalCost_j$ Capital cost of electric generator model j ($)

$TransCapitalCost_k$ Capital cost of electricity transformer model k ($)

$CondOMCost_i$ Annual operations and maintenance cost of conditioning equipment model i ($)

$GenOMCost_j$ Annual operations and maintenance cost of electric generator model j ($)

$TransOMCost_k$ Annual operations and maintenance cost of electricity transformer model k ($)

t Years of operation (years)

CDF_t Cumulative discount factor for t years of operations

(1/r -1/r(1+r)^t)

Integer Variables:

$XCond_{H,i}$ Number of conditioning equipment model i required on hub H

$XGen_{H,j}$ Number of electric generator model j required on hub H

$XTrans_{H,k}$ Number of electric transformer type k required on hub H

Objective function and constraints for hub farm:

$$
\begin{aligned}
&MINIMIZING \sum_{H,i} (XCond_{H,i} * CondCapitalCost_i + XCond_{F,i} * CondOMCost_i * CDF_t) \\
&+ \sum_{H,j} (XGen_{H,i} * GenCapitalCost_j + XGen_{F,j} * GenOMCost_j * CDF_t) \\
&+ \sum_{H,k} (XTrans_{H,k} * TransCapitalCost_j + XTrans_{F,k} * TransOMCost_k * CDF_t)
\end{aligned}
$$

$$
\begin{aligned}
&S.T. \\
&\sum_{i} (XCond_{H,i} * CondCapacity_i) \geq \sum_{F} GCapture_F * ConversionF * (1 - WRLossRate) \\
&\sum_{j} (XGen_{H,j} * GenCapacity_j) \geq \sum_{F} GCapture_F * ConversionF * (1 - WRLossRate) * (1 - CondLossRate) \\
&\sum_{k} (XTrans_{H,k} * TransCapacity_k) \geq \sum_{H,j} (XGen_{H,j} * GenElectricity_j) \\
&XCond_{H,i}, XGen_{H,j}, XTrans_{H,k} \geq 0
\end{aligned}
$$

Mathematical Modeling: Scenarios 2 & 4

In scenarios 2 and 4, biogas is captured and purified on the farms. The purified gas is then compressed to 800 psi to connect to existing natural gas pipelines in the vicinity. In Scenario 2, biogas purifiers and high-pressure compressors are installed in individual farms. In Scenario 4, water removal conditioners are required on the individual farms before gas is transported to the hub farm through the pipeline network. Biogas purifiers and high-pressure compressors are only required on the hub farm for aggregated biogas.

Scenario 2

In this formulation, the objective function minimized the capital and O&M costs for the purifiers and compressors on the individual farms. The optimization can provide the optimal configurations of equipment with various capacities and cost. The constraints equations include that the summed capacity of equipment used on the individual farm is larger than the total biogas input. The variables used in this formulation include the number of certain types of purifiers ($XP_{S,i}$) and compressors ($XC_{S,i}$) for a certain farm S, which are both assumed to be nonnegative and integer.

Sets:

S	Swine farms
P_i	Biogas purifier type i
C_j	High pressure compressor type j

Parameters:

$GCapture_S$	Annual biogas captured on farm S (mmBTU/year)
$PCapacity_i$	Capacity of purifier type i (CFH)
$CCapacity_j$	Capacity of compressor type j (CFH)
$PCapitalCost_i$	Capital cost of purifier type i ($)
$CCapitalCost_j$	Capital cost of compressor type j ($)
$POMCost_i$	Annual operations and maintenance cost of purifier type i ($)
$COMCost_j$	Annual operations and maintenance cost of compressor type j ($)
t	Years of operation (years)
CDF_t	Cumulative discount factor for t years of operations (1/r -1/r(1+r)^t)

Scalars:

r	Discount rate (7%)
ConversionF	To convert biogas production rate (mmbtu/year) into biogas flow rate (CFH) (0.2021)
PLossRate	Methane loss rate through purification (43%)

Integer Variables:

$XP_{S,i}$	Number of purifier type i required on farm S
$XC_{S,j}$	Number of compressor type j required on farm S

Objective function and constraints:

$$MINIMIZING \sum_{S,i} (XP_{S,i} * PCapitalCost_i + XP_{S,i} * POMCost_i * CDF_t)$$
$$+ \sum_{S,j} (XC_{S,i} * CCapitalCost_j + XC_{S,j} * COMCost_j / Rate_t)$$

$$S.T.$$
$$\sum_i (XP_{S,i} * PCapacity_i) \geq GCapture_s * ConversionF$$
$$\sum_j (XC_{S,j} * CCapacity_j) \geq GCapture_s * ConversionF * (1 - PLossRate)$$

Scenario 4

$$XP_{S,i}, XC_{S,j} \geq 0$$

The Scenario 4 formulation contains farm-level and hub-level optimizations. At the farm level, the objective function minimizes the total cost for water removal conditioners required for each farm and provides optimal equipment configuration. At the hub level, the objective function minimizes the total cost on the hub with optimal equipment configuration for biogas purifiers and high-pressure compressors.

The constraint equation at the farm level defines the summed capacity of water removal conditioners to be larger than the total gas input on each farm. At the hub level, the constraints define the summed capacities of biogas purifiers and the high-pressure compressor to be larger than the total gas input at the hub farm, which is aggregated from the group of farms. Variables at both levels are used to identify the number of equipment of a certain type and capacity required on a given farm. Both variables at the farm level ($XWR_{F,k}$) and the hub level ($XP_{H,i}$, $XC_{H,j}$) are assumed to be nonnegative and integer.

Optimization **at individual farm** level:

Sets:

F	Farms other than the hub farm
WR_l	Water removal conditioner type k

Parameters:

$GCapture_F$ Annual biogas captured on farm F (mmBTU/year)

$WRCapacity_l$ Capacity of water removal conditioner type i (CFH)

$WRCapitalCost_l$ Capital cost of water removal conditioner type i ($)

$WROMCost_l$ Annual operations and maintenance cost of water removal conditioner type i ($)

t Years of operation (years)

CDF_t Cumulative discount factor for t years of operations (1/r -1/r(1+r)^t)

Scalars:

r Discount rate (7%)

ConversionF To convert biogas production rate (mmbtu/year) into biogas flow rate (CFH) (0.2021)

Integer Variables:

$XWR_{F,l}$ Number of water removal conditioner type i required on farm F

Objective functions and constraints:

$$MINIMIZING \sum_{F,l} (XWR_{F,l} * WRCapitalCost_l + XWR_{F,l} * WROMCost_l * CDF_t)$$

$$S.T.$$

$$\sum_{l} (XWR_{F,l} * WRCapacity_l) \geq GCapture_F * ConversionF$$

$$XWR_{F,l} \geq 0$$

Optimization at the **hub** level:

Sets:

H Hub farm

S Swine farms

P_i Biogas purifier type i

C_j High pressure compressor type j

Parameters:

$GCapture_S$ Annual biogas captured on farm S (mmBTU/year)

$PCapacity_i$ Capacity of purifier type i (CFH)

$CCapacity_j$ Capacity of compressor type j (CFH)

$PCapitalCost_i$ Capital cost of purifier type i ($)

$CCapitalCost_j$ Capital cost of compressor type j ($)

$POMCost_i$ Annual operations and maintenance cost of purifier type i ($)

$COMCost_j$ Annual operations and maintenance cost of compressor type j ($)

t Years of operation (years)

CDF_t Cumulative discount factor for t years of operations (1/r -1/r(1+r)^t)

Scalars:

r Discount rate (7%)

ConversionF To convert biogas production rate (mmbtu/year) into biogas flow rate (CFH) (0.2021)

WRLossRate Methane loss rate through water removal (3%)

PLossRate Methane loss rate through purification (43%)

Integer Variables:

$XP_{H,i}$ Number of purifier type i required on the hub

$XC_{H,j}$ Number of compressor type j required on the hub

Objective functions and constraints:

$$MINIMIZING \sum_{H,i}(XP_{H,i} * PCapitalCost_i + XP_{H,i} * POMCost_i * CDF_t)$$
$$+\sum_{H,j}(XC_{H,i} * CCapitalCost_j + XC_{H,j} * COMCost_j * Rate_t)$$

$$S.T.$$
$$\sum_{i}(XP_{H,i} * PCapacity_i) \geq \sum_{S,j} GCapture_S * ConversionF * (1 - WRLossRate)$$
$$\sum_{j}(XC_{H,j} * CCapacity_j) \geq \sum_{S,j} GCapture_S * ConversionF * (1 - WRLossRate) * (1 - PLossRate)$$
$$XP_{H,i}, XC_{H,j} \geq 0$$

D.2. Biogas Infrastructure Economies of Scale

The drive for biogas development owes in part to the potential of the technology to have a great impact on reducing CO_2 emissions. To do so, biogas must be deployed at a large scale. Although biogas deployment will be subject to a series of challenges, including regulatory and climate policy, the degree of biogas deployment will also be determined by the economy of scale of biogas technology itself.

Biogas technology achieves economies of scale if the increase in the amount of biogas captured and the possibility of cooperation between biogas sources will lower the average cost of capturing, transporting, and generating electricity per unit. The economy of scale of biogas capture technology is important for understanding and designing the biogas spatial organization, cooperation between sources, and the scale of the technology deployment.

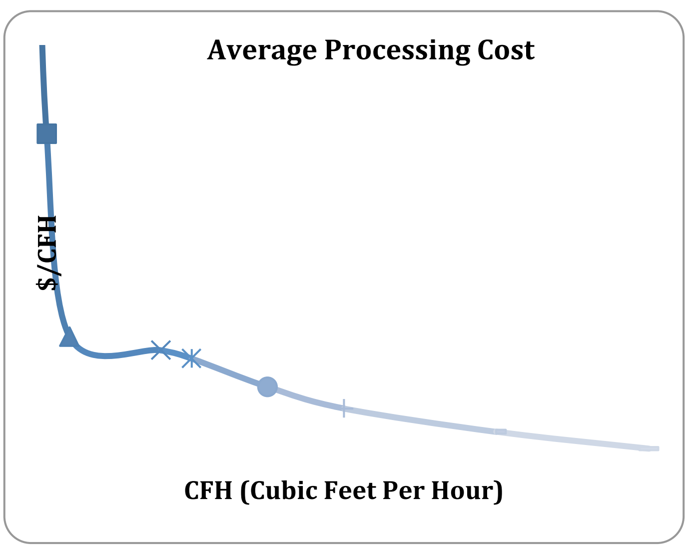


Figure E.2.1. Average processing cost decreases as the operation scales up

These economies of scale can be derived from biogas equipment engineering principles, which can be characterized by the decrease in the average cost to process a unit of biogas as the operation scales up. The hypothetical data shown in Figure E.2.1 demonstrate that the average processing cost-per-unit of biogas decreases at a decreasing rate as the scale of operation increases. This means that there is an incentive to aggregate biogas from multiple sources into a hub to reduce costs. The OptimaBIOGAS will determine whether the efficiency gain can offset the additional cost to transport the biogas into the hub.

D.3. Heuristic Methods

Heuristic methods are referred to as experience-based problem-solving strategies. When the theoretical methods are impractical due to limited time and resources, heuristic methods can be used to speed up the process of finding a satisfactory solution. The solution cannot necessarily be proven to be correct but is a good and admissible solution (Cooper 1964). OptimaBIOGAS cannot automatically group hundreds of farms automatically. The grouping of farms is conducted iteratively given the biogas production capacities of the farms, the distance between farms, and spatial obstacles to biogas pipeline construction. By taking these factors into account, a reasonable grouping can be obtained to produce a satisfactory LCOE result.

The optimization process can be further improved using the method shown in Figure E.3.1. An initial spatial arrangement will group the swine farms and determine the most optimal hub. Through both spatial permutation and spatial optimization, the model will output the most optimal network. The spatial analysis is followed by mathematical modeling, which will determine the biogas supply, the pipe sizes, and where the pipes merge. The pipeline network cost will be minimized during the modeling process. The pipeline transportation cost of the system is then input as a fixed cost in the mathemtical modeling for equipment configuration. A LCOE given optimal transportation and equipment costs can then be determined with the results to calculate the costs and profits. In the present heuristic optimization, farms are added or subtracted in the initial farm group until the lowest LCOE is reached. The resulting grouping and optimal pipeline routes are also used to create a spatial map of the farm groups, the hubs, and the pipeline network.

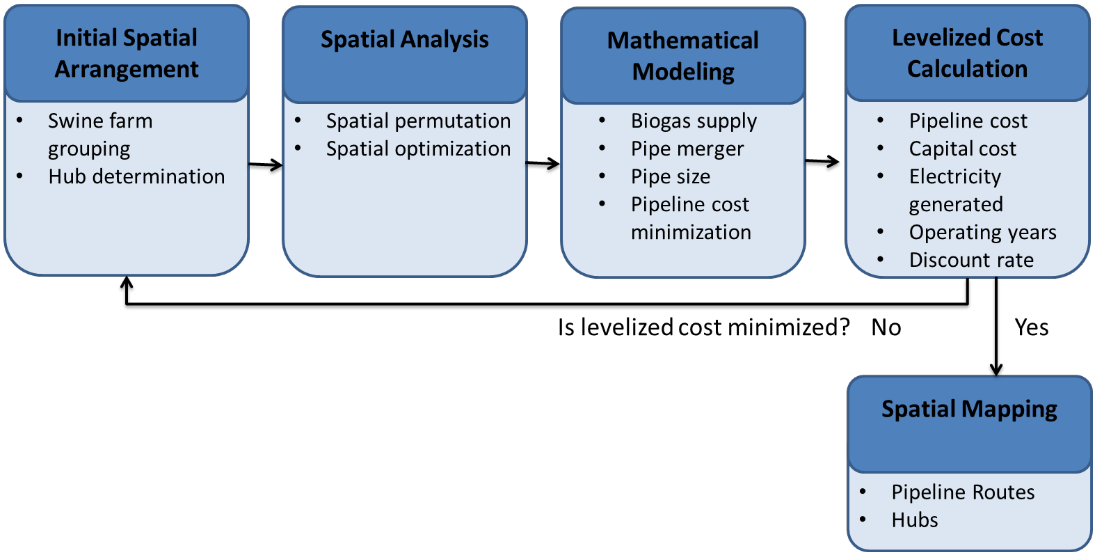


Figure E.3.1. Model design

Appendix E. Pipeline Modeling

E.1. Pipeline Engineering Principle

Chandel et al. developed a pipeline model that yields the design parameters and costs for a trunkline on the basis of the diameter of pipes required to transport different mass flows of CO_2, the number and spacing of booster pumps needed to keep the CO_2 in a supercritical state, the power required to accomplish this high-pressure transport, and specific costs of CO_2 transport (e.g., pipeline costs, pump costs, O&M costs, and the cost of electricity for transport) (Chandel, Pratson, and Williams 2010). Chandel's study derived the pipeline costs from existing natural gas pipelines published in 2004 (Parker 2004). OptimaBiogas utilizes the pipeline engineering principle from this study and incorporates the specifications and cost of the natural gas pipelines (Source: William Simmons, Cavanaugh and Associates P.A.).

OptimaBiogas models cost minimization through a series of constraints. One such constraint is to transform mass flow of biogas to pipe size. Another constraint is to transform pipe size to pipe cost.

From the relationship between biogas flow rate and pipe size (Table F.1.1), we applied separable programming to approximate the relationships between biogas flow and pipe size (Figure F.1.1).

Table F.1.1. Natural gas flow rate and its corresponding pipe size

Flow (CFH)	Pipe Size in Diameter (inch)
300	0.5
1828	1
11157	2
31988	3
66030	4

Source: William Simmons, Cavanaugh and Associates P.A.

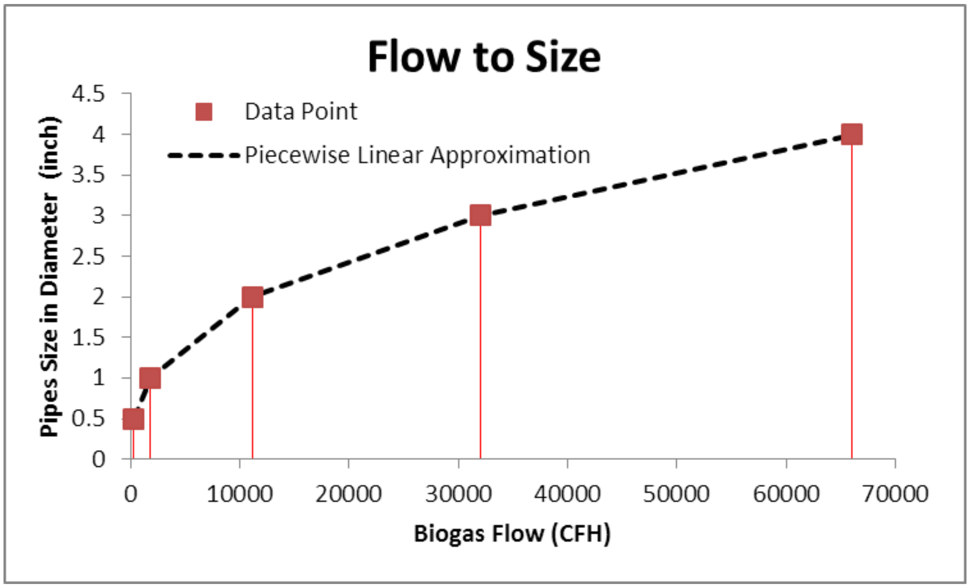


Figure F.1.1. Mass flow in cubic feet hour (CFH) for different pipe diameters.

The cost minimization requires another constraint to transform pipe size to baseline development cost per kilometer of pipeline by using the pipeline model developed by a separable programming model using the data of the relationship between pipe size and capital cost (Table F.1.2, Figure F.1.2).

Table F.1.2. Natural gas pipe size and its corresponding unit cost

Pipe Size in Diameter (inch)	Pipe Cost (1000$/km)
0.5	34.575
1	36.075
2	39.354
3	42.571
4	45.913

Source: William Simmons, Cavanaugh and Associates P.A.

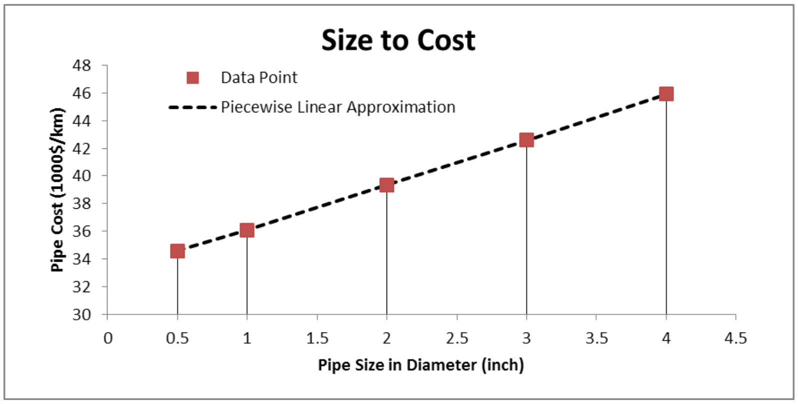


Figure F.1.2. Capital cost ($/km) for different pipe diameters.

E.2.Mathematical Model: Separable Programming

The core engine of OptimaBiogas is a cost minimization optimization formulated as a mixed-integer programming (MIP) model. The model is an extension of the basic transportation problem discussed by McCarl et al. (McCarl & Spreen 2003). The model determines the volume of biogas flow across a pipeline segment and a pipe size, plus whether or not to build a pipeline segment between two nodes.

Sets:

S	*sources farm*
R	*reservoirhub farm*
P, i, j, k	*point which may include sources + reservoirs*
m	*set of steps for flow to size*
n	*set of steps for size to cost*

Parameters:

$SCapture_S$	*annual biogas captured in source S (CFH/year)*
$NormDist_{i,j}$	*normalized distance between point i and j*
$FlowToSizeFlow_m$	*Step function for pipe flow for flow to size transformation*
$FlowToSizeSize_m$	*Step function for pipe size for flow to size transformation*

SizeToCostSize$_n$ *Step function for pipe size for size to cost transformation*

SizeToCostCost$_n$ *Step function for pipe cost for size to cost transformation*

Scalars:

THorizon *life time of a biogas project*

MaxSize *maximum pipe size (inches)*

Continuous Decision Variables:

XFlow$_{i,j}$ *mass flow between point i and j (mtons/year)*

XSize$_{i,j}$ *pipe size between point i and j (inches)*

XCostPerKm$_{i,j}$ *pipeline baseline unit cost per km between point i and j ($/km)*

Continuous Adjacent Variables:

$\lambda_{i,j,m}$ *combination variables to linearize flow to size that force maximum of two adjacent λ_m & λ_{m+1} non zero*

$\beta_{i,j,n}$ *combination variable that linearize size to cost that force maximum of two adjacent β_n & β_{n+1} non zero*

The model:

$$\textbf{MINIMIZE} \sum_i \sum_j NormDist_{i,j}\, XCostPerKm_{i,j} + \sum_R \sum_S XFlow_{S,R} * THorizon \quad \textbf{[4]}$$

S.T

$$\sum_i XFlow_{i,k} + SCapture_k - \sum_j XFlow_{k,j} \le 0 \quad \forall\, k \in S \quad \textbf{[5]}$$

$$XFlow_{i,j} - \sum_{m} \lambda_{i,j,m} * FlowToSizeFlow_m = 0 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [6]$$

$$\sum_{m} \lambda_{i,j,m} = 1 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [7]$$

$$XSize_{i,j} - \sum_{m} \lambda_{i,j,m} * FlowToSizeSize_m = 0 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [8]$$

$$XSize_{i,j} - \sum_{n} \beta_{i,j,n} * SizeToCostSize_n = 0 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [9]$$

$$\sum_{n} \beta_{i,j,n} = 1 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [10]$$

$$XCostKm_{i,j} - \sum_{n} \beta_{i,j,n} * SizeToCostCost_n = 0 \quad \forall\, i, j \in P \text{ where } i \neq j \qquad [11]$$

The objective function of OptimaBiogas (Equation 4) is to globally minimize pipeline development costs, operating costs, and biogas injection costs over the project time horizon (infrastructure lifespan), which enables design of the most cost-effective biogas infrastructure. The setup of global cost minimization also facilitates an active search of the best configuration This setup also determines whether the cost associated with a trunkline's greater distance is offset by savings from engineering efficiencies of a bigger pipe diameter. Hence, pipeline convergence is facilitated to reduce overall pipeline cost during the cost minimization process.

The flow constraint (Equation 5) ensures that the flow of biogas coming to a point plus the biogas generated at that point is less than or equal to the flow of boigas coming out. Equation (5) facilitates a mechanism that a power plant is considered not only as a biogas source but also as a potential hub in which several smaller pipelines merge to become a bigger pipeline to gain efficiency. Equation (6) is a separable program to compute the combination of $\lambda_{i,j,m}$ and $\lambda_{i,j,m+1}$ to match the pipe flow for pipeline segment from node i to node j. Separable programming is a mechanism that is utilized to linearize non-linear equations by separating an non-linear equation at different intervals and then each is approximated with a linear equation. Equation (7) is to make sure the convexity of $\lambda_{i,j,m}$ *which is the characteristic of ..* Equation (8) is a separable program to use $\lambda_{i,j,m}$ and $\lambda_{i,j,m+1}$ to compute the pipe size for pipeline segment from node i to node j. Equation (9) is a separable program to compute the combination of $\beta_{i,j,n}$ and $\beta_{i,j,n+1}$ that matches the pipe size for pipeline segment from node i to j. Equation (10) is to make sure the convexity of combination of $\beta_{i,j,n}$ and $\beta_{i,j,n+1}$. Equation (11) is a separable program that uses $\beta_{i,j,n}$ and $\beta_{i,j,n+1}$. to compute the pipe cost for pipeline segment from node i to node j.

OptimaBiogas is non-temporal with the assumption that pipeline infrastructure is used to its constructed capacity over time. The total injection cost is computed using average cost over the lifetime of the biogas system.

Appendix F. Pipeline Specifications

The tables in this appendix list pipeline segments for each farm in scenarios 3 and 4 as well as their lengths and sizes. In Scenario 3, only low-pressure pipelines are employed for gas transportation between farms. In Scenario 4, in addition to low-pressure pipelines, high-pressure pipelines are required to connect purified and pressurized gas from hubs to existing pipelines. All pipelines required in scenarios 3 and 4 are listed below.

F.1.Pipeline Specifications for Scenario 3

Table F.1.1. Pipeline specification data for Scenario 3, Stage 1

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.146700	-78.130000	35.131055	-78.235197	548.41	1	10.548
35.079011	-78.262294	35.073613	-78.265144	214.87	0.5	0.915
35.087800	-78.211700	35.072042	-78.215381	1119.2	1	1.890
35.052866	-78.241352	35.053366	-78.215205	821.32	1	2.873
35.072042	-78.215381	35.053366	-78.215205	1510.78	1	2.400
35.131055	-78.235197	35.087800	-78.211700	877.46	1	5.698
35.073613	-78.265144	35.052866	-78.241352	429.74	1	3.356
35.045000	-78.077800	35.046700	-78.090000	214.87	0.5	1.119
35.061100	-78.053300	35.069700	-78.053100	706.97	1	1.289
35.065300	-78.067800	35.057500	-78.077800	2261.91	2	1.437
35.042500	-78.033300	35.061100	-78.053300	384.64	1	2.844
35.069700	-78.053100	35.065300	-78.067800	1999.27	2	1.681
35.084700	-78.048300	35.069700	-78.053100	1023.69	1	1.638
35.081700	-78.065000	35.084700	-78.048300	429.77	1	1.456
35.057500	-78.077800	35.046700	-78.090000	2508.14	2	1.941
35.046700	-78.090000	35.063900	-78.125000	3197.96	2	4.138
35.018300	-78.133300	35.054700	-78.140300	4330.16	2	4.510
35.063900	-78.125000	35.054700	-78.140300	3436.73	2	1.942
35.053366	-78.215205	35.049105	-78.176486	2630.56	2	3.764
35.000136	-78.222075	35.011463	-78.182833	783.16	1	4.245
35.049105	-78.176486	35.011463	-78.182833	2890.42	2	4.565
35.011463	-78.182833	35.018300	-78.133300	3936.21	2	5.528
34.968100	-78.154200	34.960405	-78.170441	214.87	0.5	1.772
34.936100	-78.127400	34.928158	-78.151152	268.61	0.5	2.636
34.960405	-78.170441	34.945583	-78.156316	1719.23	1	2.308
34.945583	-78.156316	34.928158	-78.151152	1934.1	2	2.145
34.946275	-78.207386	34.960405	-78.170441	1006.53	1	4.044
34.981477	-78.163125	34.960405	-78.170441	273.98	0.5	2.394

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.928158	-78.151152	34.903997	-78.167027	2672.71	2	3.453
34.903997	-78.167027	34.889689	-78.178956	2906.25	2	2.193
34.889689	-78.178956	34.883219	-78.163722	3598.66	2	1.723
34.945400	-78.232719	34.946275	-78.207386	467.07	1	2.624
34.954292	-78.241102	34.945400	-78.232719	225.33	0.5	1.438
34.954036	-78.214186	34.946275	-78.207386	265.48	0.5	1.243
34.869797	-78.273688	34.826330	-78.268677	501.38	1	5.727
34.826330	-78.268677	34.841025	-78.195061	808.79	1	7.506
34.876038	-78.275555	34.869797	-78.273688	273.08	0.5	1.036
34.780600	-78.169400	34.808300	-78.183300	2132.76	2	3.569
34.808300	-78.183300	34.848300	-78.159700	2425.99	2	5.404
34.753300	-78.111700	34.765300	-78.138900	365.31	1	2.930
34.765300	-78.138900	34.780600	-78.169400	1141.59	1	3.942
34.806100	-78.096900	34.814400	-78.088900	238.77	0.5	1.236
34.793100	-78.119700	34.765300	-78.138900	365.31	1	3.953
34.814400	-78.088900	34.845000	-78.125600	604.08	1	7.006
34.773455	-78.197858	34.780600	-78.169400	351.88	1	3.041
34.882500	-78.109400	34.872500	-78.125800	1200.92	1	1.942
34.887500	-78.131400	34.872500	-78.125800	1810.15	1	1.937
34.873300	-78.150000	34.867200	-78.151400	8521.41	2	0.882
34.872500	-78.125800	34.873300	-78.150000	3650.36	2	2.572
34.883300	-78.085600	34.882500	-78.109400	273.98	0.5	2.572
34.883219	-78.163722	34.873300	-78.150000	4479.89	2	1.793
34.848300	-78.159700	34.867200	-78.151400	3895	2	2.155
34.845000	-78.125600	34.848300	-78.159700	878.06	1	3.515
34.841025	-78.195061	34.866922	-78.189213	1189.33	1	3.150
34.866922	-78.189213	34.867200	-78.151400	2207.07	2	3.619
34.852200	-77.969700	34.887200	-77.978100	1927.11	2	4.604
34.848300	-77.949200	34.852200	-77.969700	953.56	1	1.866
34.876100	-78.023600	34.852200	-77.969700	273.98	0.5	6.380
34.894400	-77.894400	34.893100	-77.897200	273.98	0.5	0.530
34.899400	-77.928300	34.913100	-77.953100	1296.46	1	3.196
34.843225	-77.886975	34.847500	-77.936100	268.61	0.5	4.863
34.887200	-77.978100	34.913100	-77.953100	2685.49	2	3.890
34.847500	-77.936100	34.848300	-77.949200	542.6	1	1.368
34.893100	-77.897200	34.899400	-77.928300	976.83	1	3.109
34.930000	-77.936700	34.954200	-77.925000	6432.85	2	3.100
34.945000	-77.905300	34.954200	-77.925000	417.85	1	2.327
34.974970	-77.865830	34.988600	-77.878900	410.96	1	2.470
34.954200	-77.925000	34.968300	-77.925000	7058.85	2	2.044

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.913100	-77.953100	34.930000	-77.936700	5702.23	2	2.535
34.947800	-78.036700	34.954400	-78.021400	274.56	0.5	1.772
34.922800	-77.959700	34.913100	-77.953100	1386.03	1	1.243
34.954400	-78.021400	34.922800	-77.959700	752.1	1	7.459
34.968300	-77.925000	35.009700	-77.946100	7266.83	2	5.307
34.988600	-77.878900	34.968300	-77.925000	625.83	1	4.776
35.054200	-77.980000	35.038900	-77.927800	502.29	1	5.509
35.061900	-77.997800	35.054200	-77.980000	228.31	0.5	2.078
35.044596	-77.936535	35.038900	-77.927800	221.97	0.5	1.185
35.038900	-77.927800	35.009700	-77.946100	2700.33	2	4.059
35.056700	-77.873300	35.073600	-77.956900	365.31	1	7.841
35.073600	-77.956900	35.038900	-77.927800	1259.76	1	5.341
35.031900	-77.875000	35.038900	-77.927800	238.77	0.5	5.204
35.075800	-77.969400	35.073600	-77.956900	483.48	1	1.368

Table F.1.2. Pipeline Specification Data for Scenario 3 Stage 2

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.325479	-78.134296	35.334700	-78.158100	1217.66	1	2.866
35.329400	-78.143600	35.334700	-78.158100	214.87	0.5	1.461
35.299400	-78.138100	35.299400	-78.141700	214.87	0.5	0.530
35.307800	-78.208900	35.334700	-78.158100	671.51	1	5.828
35.320800	-78.256900	35.307800	-78.208900	456.64	1	4.975
35.306400	-78.067800	35.299700	-78.103100	429.77	1	4.135
35.299700	-78.103100	35.325479	-78.134296	989.35	1	4.519
35.299400	-78.141700	35.334700	-78.158100	453.64	1	5.111
34.961700	-77.665000	34.891100	-77.685000	797.97	1	8.443
34.926900	-77.625300	34.961700	-77.665000	328.31	1	5.735
34.882200	-77.568900	34.891100	-77.685000	261.15	0.5	11.851
34.895300	-77.750000	34.883300	-77.746700	314.87	1	1.392
34.870000	-77.752200	34.883300	-77.746700	645.82	1	1.009
34.883300	-77.819400	34.870000	-77.752200	213.38	0.5	6.349
34.891100	-77.685000	34.883300	-77.746700	1287.43	1	6.131
34.828300	-77.793600	34.870000	-77.752200	214.87	0.5	6.314
34.731900	-77.718100	34.731100	-77.732800	456.61	1	1.577
34.773300	-77.840300	34.731900	-77.796400	536.62	1	6.497
34.755600	-77.683300	34.731900	-77.718100	228.31	0.5	4.514
34.749700	-77.748100	34.731100	-77.732800	273.98	0.5	2.662

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.731100	-77.732800	34.725000	-77.758300	1265.1	1	2.584
34.762500	-77.829400	34.773300	-77.840300	262.64	0.5	2.581
34.731900	-77.796400	34.725000	-77.758300	901.94	1	3.855
34.698100	-77.736400	34.731100	-77.732800	319.63	1	4.563
35.139400	-77.474400	35.106800	-77.572836	268.61	0.5	10.319
35.161400	-77.681370	35.171500	-77.669370	684.2	1	1.777
35.171500	-77.669370	35.181700	-77.613714	925.94	1	5.664
35.106800	-77.572836	35.078100	-77.565800	1946.08	2	3.636
35.181700	-77.613714	35.106800	-77.572836	1199.93	1	10.141
35.132000	-77.673877	35.161400	-77.681370	262.64	0.5	3.669
35.020800	-77.528300	35.078100	-77.565800	1761.08	1	7.657
34.989400	-77.512500	35.050000	-77.438300	826.33	1	9.880
35.050000	-77.438300	35.020800	-77.528300	1315.9	1	9.373
35.043700	-77.687272	34.989400	-77.512500	548.41	1	17.961
35.078100	-77.652800	35.043700	-77.687272	212.64	0.5	5.371
35.206500	-77.785869	35.179300	-77.797182	268.61	0.5	3.252
35.276200	-77.823617	35.255000	-77.822606	537.2	1	2.652
35.245900	-77.795681	35.255000	-77.822606	273.98	0.5	2.878
35.179300	-77.797182	35.164538	-77.799262	2216.87	2	1.801
35.198200	-77.818120	35.179300	-77.797182	1724.41	1	3.001
35.255000	-77.822606	35.239506	-77.828245	1079.8	1	1.991
35.288300	-77.838900	35.276200	-77.823617	214.87	0.5	2.291
35.213900	-77.904200	35.198200	-77.818120	214.87	0.5	8.245
35.239506	-77.828245	35.198200	-77.818120	1294.67	1	5.537
35.056900	-77.800300	35.069200	-77.791700	678.2	1	1.840
35.069200	-77.791700	35.127800	-77.798900	1089.16	1	7.133
35.020300	-77.807200	35.028600	-77.791700	248.46	0.5	1.772
35.138300	-77.827500	35.164538	-77.799262	2439.97	2	4.115
35.138100	-77.882500	35.138300	-77.827500	718.1	1	5.564
35.127800	-77.798900	35.138300	-77.827500	1483.11	1	3.429
35.028600	-77.791700	35.056900	-77.800300	463.33	1	3.649
35.126900	-77.896400	35.138100	-77.882500	477.54	1	2.043
35.271400	-78.171700	35.238300	-78.163900	434.23	1	4.240
35.276700	-78.253300	35.271400	-78.171700	214.87	0.5	7.704
35.236400	-78.116700	35.238300	-78.163900	966.97	1	4.667
35.230000	-78.172200	35.238300	-78.163900	219.36	0.5	1.201
35.199114	-78.251505	35.206019	-78.321011	2111.09	2	6.460
35.144411	-78.263377	35.155600	-78.265800	214.87	0.5	1.475
35.206019	-78.321011	35.179519	-78.358555	2340.88	2	5.505
35.152794	-78.271369	35.155600	-78.265800	270.1	0.5	0.978
35.186605	-78.187138	35.199114	-78.251505	495.43	1	6.613

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.163163	-78.273680	35.199114	-78.251505	1353.01	1	4.719
35.155600	-78.265800	35.163163	-78.273680	804.61	1	1.429
35.047188	-78.302744	35.092269	-78.300733	211.9	0.5	5.527
35.101408	-78.267947	35.092269	-78.300733	219.36	0.5	3.539
35.092269	-78.300733	35.096700	-78.368900	650.61	1	6.657
35.096700	-78.368900	35.124116	-78.381274	1089.33	1	3.547
35.113408	-78.426333	35.134591	-78.450300	223.85	0.5	3.536
35.140816	-78.472502	35.134591	-78.450300	219.36	0.5	2.615
35.155972	-78.400119	35.146044	-78.387802	1269.48	1	2.085
35.122205	-78.492827	35.134591	-78.450300	300.09	1	4.302
35.134591	-78.450300	35.155972	-78.400119	971.59	1	5.831
35.124116	-78.381274	35.152311	-78.373088	1327.52	1	3.765
35.200558	-78.402786	35.188350	-78.402519	686.76	1	1.541
35.179519	-78.358555	35.165855	-78.351816	2772.13	2	1.938
35.216722	-78.415733	35.200558	-78.402786	257.02	0.5	2.985
35.188350	-78.402519	35.146044	-78.387802	928.51	1	5.854
35.146044	-78.387802	35.152311	-78.373088	2426.29	2	3.005
35.152311	-78.373088	35.165855	-78.351816	3964.57	2	2.576
35.005394	-78.402063	35.005511	-78.436102	274.2	0.5	3.318
35.065069	-78.458086	35.005511	-78.436102	260.33	0.5	7.393
34.918169	-78.313866	34.911742	-78.372683	630.32	1	6.079
34.914686	-78.297930	34.918169	-78.313866	410.96	1	1.617
34.944211	-78.396286	34.939261	-78.420022	1074.43	1	2.531
34.947455	-78.450580	34.939261	-78.420022	1423.8	1	2.967
35.005511	-78.436102	34.947455	-78.450580	909.84	1	6.921
34.960588	-78.489094	34.947455	-78.450580	238.77	0.5	4.174
34.911742	-78.372683	34.944211	-78.396286	849.68	1	5.204
34.759775	-78.674275	34.846472	-78.646513	628.25	1	10.508
34.766825	-78.589936	34.759775	-78.674275	255.18	0.5	8.526
34.797758	-78.543247	34.819191	-78.544711	800.14	1	2.651
34.846472	-78.646513	34.932667	-78.632761	1038.64	1	13.886
34.838905	-78.531000	34.819191	-78.544711	2296.03	2	2.949
34.932667	-78.632761	34.838905	-78.531000	2022.04	2	14.575
34.823958	-78.441639	34.797758	-78.543247	252.18	0.5	17.559
34.994466	-78.586933	34.966888	-78.589944	238.77	0.5	3.305
34.966888	-78.589944	34.932667	-78.632761	764.05	1	5.957

Table F.1.3. Pipeline specification data for Scenario 3, Stage 3

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.871336	-79.302844	34.763285	-79.349904	919.25	1	13.635
34.600053	-79.377925	34.624506	-79.390653	351.88	1	3.244
34.638850	-79.436017	34.624506	-79.390653	558.1	1	4.671
34.693053	-79.342000	34.763285	-79.349904	2879.82	2	9.010
34.624506	-79.390653	34.693053	-79.342000	1566.59	1	10.167
34.784909	-79.390212	34.763285	-79.349904	346.51	1	6.396
34.692227	-79.466016	34.638850	-79.436017	295.46	0.5	7.844
34.887800	-79.318627	34.871336	-79.302844	590.95	1	2.503
34.507897	-79.190111	34.452944	-79.128642	1477.3	1	8.767
34.545250	-79.208794	34.521639	-79.206414	295.46	0.5	3.297
34.513906	-79.228247	34.521639	-79.206414	590.92	1	2.621
34.380206	-79.085872	34.359981	-79.080517	214.87	0.5	2.702
34.359981	-79.080517	34.452944	-79.128642	708.43	1	14.867
34.521639	-79.206414	34.507897	-79.190111	1181.84	1	2.396
34.484069	-79.228192	34.513906	-79.228247	295.46	0.5	3.538
34.336367	-78.976700	34.293100	-78.965800	405.9	1	5.524
34.243600	-78.861400	34.293100	-78.965800	658.1	1	12.057
34.519136	-78.382786	34.524486	-78.474922	373.08	1	8.906
34.524486	-78.474922	34.541061	-78.543486	641.69	1	6.909
34.504702	-78.560475	34.541061	-78.543486	561.1	1	4.762
34.578625	-78.546091	34.541061	-78.543486	932.06	1	4.448
34.592744	-78.561430	34.578625	-78.546091	658.07	1	2.396
34.583930	-78.599241	34.592744	-78.561430	438.72	1	3.951
34.490183	-78.853822	34.455800	-78.839400	328.31	1	4.342
34.416700	-78.691700	34.356900	-78.733900	343.23	1	8.262
34.368100	-78.786100	34.455800	-78.839400	1044.59	1	11.320
34.356900	-78.733900	34.354700	-78.775800	562.59	1	4.168
34.354700	-78.775800	34.368100	-78.786100	781.95	1	1.952
34.403300	-78.937800	34.455800	-78.839400	295.46	0.5	11.650
34.455800	-78.839400	34.496205	-78.772841	1930.99	2	7.772
34.628138	-78.722822	34.591611	-78.798319	781.95	1	8.338
34.534441	-78.715386	34.547755	-78.745588	319.63	1	3.533
34.571938	-78.823838	34.589905	-78.817327	262.64	0.5	2.293
34.589905	-78.817327	34.591611	-78.798319	492.43	1	2.074
34.496205	-78.772841	34.547755	-78.745588	2527.91	2	6.862
34.637158	-78.689033	34.628138	-78.722822	208.92	0.5	4.086
34.591611	-78.798319	34.547755	-78.745588	1569.84	1	7.189

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.746594	-78.956739	34.789342	-79.012822	540.95	1	8.190
34.745044	-78.917589	34.746594	-78.956739	298.46	0.5	3.815
34.707683	-78.237938	34.688263	-78.180858	2635.43	2	6.181
34.747738	-78.231486	34.707683	-78.237938	1546.65	1	4.815
34.725155	-78.333272	34.707683	-78.237938	730.62	1	9.185
34.768025	-78.247361	34.747738	-78.231486	1318.35	1	2.848
34.699461	-78.332383	34.725155	-78.333272	273.98	0.5	3.665
34.807358	-78.299680	34.775663	-78.261705	761.74	1	5.187
34.775663	-78.261705	34.768025	-78.247361	1090.04	1	1.829
34.605000	-77.982500	34.659743	-78.068863	533.29	1	10.990
34.659743	-78.068863	34.688263	-78.180858	828.75	1	11.354
34.548300	-78.032200	34.605000	-77.982500	270.65	0.5	8.323
35.422500	-77.768100	35.412500	-77.805800	443.95	1	4.534
35.436400	-77.815300	35.422500	-77.768100	220.1	0.5	4.922
35.412500	-77.805800	35.370000	-77.833300	712.56	1	5.774
35.423300	-77.874400	35.370000	-77.833300	214.87	0.5	7.107
35.349700	-77.830000	35.370000	-77.833300	429.77	1	2.603
35.566400	-77.705600	35.516900	-77.690300	279.79	0.5	6.331
35.508300	-77.702800	35.516900	-77.690300	214.87	0.5	1.777
35.516900	-77.690300	35.525800	-77.638900	1948.56	2	5.063
35.531700	-77.740300	35.516900	-77.690300	1181.56	1	5.171
35.506700	-77.863300	35.504251	-77.821267	214.87	0.5	4.366
35.504251	-77.821267	35.511400	-77.800000	510.33	1	2.124
35.511400	-77.800000	35.531700	-77.740300	816.25	1	7.578
35.515800	-77.598900	35.525800	-77.638900	1690.05	1	4.069
35.441100	-77.530600	35.478300	-77.580600	817.08	1	6.612
35.478300	-77.580600	35.489400	-77.610300	1067.77	1	3.180
35.489400	-77.610300	35.515800	-77.598900	1354.28	1	3.197
35.473100	-77.499200	35.441100	-77.530600	497.44	1	5.019
35.485800	-77.495872	35.473100	-77.499200	223.85	0.5	2.394
35.504400	-77.134700	35.528300	-77.174836	322.33	1	5.142
35.521200	-77.250548	35.528300	-77.174836	223.85	0.5	7.585
35.547100	-77.177350	35.540700	-77.170136	322.33	1	1.243
35.540700	-77.170136	35.528300	-77.174836	537.2	1	1.488
36.305346	-77.149872	36.373900	-77.104400	293.23	0.5	9.381
36.318100	-77.251400	36.373900	-77.104400	302.32	1	15.407
35.836700	-76.463300	35.888900	-76.535800	293.23	0.5	10.130
35.169856	-78.690347	35.126086	-78.652589	274.2	0.5	6.908
35.126086	-78.652589	35.115792	-78.645961	603.25	1	1.598
35.188405	-78.575938	35.115792	-78.645961	626.52	1	11.713

F.2. Pipeline Specification for Scenario 4

Table F.2.1. Pipeline specification data for Scenario 4, Stage 1 (90 psi)

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.044596	-77.936535	35.0389	-77.9278	221.97	0.5	1.185
35.056700	-77.873300	35.0736	-77.9569	365.31	1	7.841
35.073600	-77.956900	35.0389	-77.9278	1259.76	1	5.341
35.009700	-77.946100	35.0389	-77.9278	593.62	1	4.049
35.031900	-77.875000	35.0389	-77.9278	238.77	0.5	5.204
35.075800	-77.969400	35.0736	-77.9569	483.48	1	1.368
35.054200	-77.980000	35.0619	-77.9978	3065.64	2	2.078
35.061900	-77.997800	35.0425	-78.0333	3293.94	2	4.061
35.038900	-77.927800	35.0542	-77.98	2791.65	2	5.511
35.042500	-78.033300	35.0611	-78.0533	3678.58	2	2.844
35.061100	-78.053300	35.0697	-78.0531	4000.92	2	1.289
35.065300	-78.067800	35.0575	-78.0778	5555.86	2	1.437
35.069700	-78.053100	35.0653	-78.0678	5293.22	2	1.681
35.084700	-78.048300	35.0697	-78.0531	1023.69	1	1.638
35.081700	-78.065000	35.0847	-78.0483	429.77	1	1.456
35.045000	-78.077800	35.0467	-78.09	214.87	0.5	1.119
35.057500	-78.077800	35.0467	-78.09	5802.09	2	1.941
35.079011	-78.262294	35.073613	-78.265144	214.87	0.5	0.915
35.087800	-78.211700	35.072042	-78.215381	570.79	1	1.890
35.052866	-78.241352	35.053366	-78.215205	821.32	1	2.873
35.072042	-78.215381	35.053366	-78.215205	962.37	1	2.400
35.131055	-78.235197	35.0878	-78.2117	329.05	1	5.698
35.073613	-78.265144	35.052866	-78.241352	429.74	1	3.356
35.146700	-78.130000	35.0639	-78.125	548.41	1	11.617
35.054700	-78.140300	35.0639	-78.125	2707.32	2	1.942
35.053366	-78.215205	35.049105	-78.176486	2082.15	2	3.764
35.049105	-78.176486	35.0547	-78.1403	2342.01	2	4.655
35.018300	-78.133300	35.011463	-78.182833	393.95	1	5.430
35.000136	-78.222075	35.011463	-78.182833	783.16	1	4.245
34.945000	-77.905300	34.9542	-77.925	417.85	1	2.327
34.974970	-77.865830	34.9886	-77.8789	410.96	1	2.470
34.968300	-77.925000	34.9542	-77.925	840.7	1	2.044
34.988600	-77.878900	34.9683	-77.925	625.83	1	4.776
34.780600	-78.169400	34.8083	-78.1833	2736.84	2	3.569
34.753300	-78.111700	34.7653	-78.1389	365.31	1	2.930
34.765300	-78.138900	34.7806	-78.1694	1745.67	1	3.942

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.806100	-78.096900	34.7931	-78.1197	604.08	1	3.438
34.793100	-78.119700	34.7653	-78.1389	969.39	1	3.953
34.814400	-78.088900	34.8061	-78.0969	365.31	1	1.336
34.773455	-78.197858	34.7806	-78.1694	351.88	1	3.041
34.848300	-78.159700	34.866922	-78.189213	864.93	1	3.747
34.845000	-78.125600	34.8483	-78.1597	273.98	0.5	3.515
34.869797	-78.273688	34.82633	-78.268677	501.38	1	5.727
34.826330	-78.268677	34.866922	-78.189213	808.79	1	9.241
34.876038	-78.275555	34.869797	-78.273688	273.08	0.5	1.036
34.882500	-78.109400	34.8725	-78.1258	1200.92	1	1.942
34.887500	-78.131400	34.8725	-78.1258	1810.15	1	1.937
34.867200	-78.151400	34.8733	-78.15	1181.89	1	0.882
34.873300	-78.150000	34.883219	-78.163722	5223.42	2	1.793
34.872500	-78.125800	34.8733	-78.15	3650.36	2	2.572
34.883300	-78.085600	34.8825	-78.1094	273.98	0.5	2.572
34.883219	-78.163722	34.889689	-78.178956	6104.65	2	1.723
34.945400	-78.232719	34.946275	-78.207386	467.07	1	2.624
34.960405	-78.170441	34.9681	-78.1542	1230.38	1	1.772
34.954292	-78.241102	34.9454	-78.232719	225.33	0.5	1.438
34.946275	-78.207386	34.960405	-78.170441	1006.53	1	4.044
34.954036	-78.214186	34.946275	-78.207386	265.48	0.5	1.243
34.808300	-78.183300	34.841025	-78.195061	3030.07	2	4.117
34.841025	-78.195061	34.866922	-78.189213	3410.6	2	3.150
34.866922	-78.189213	34.889689	-78.178956	6102.06	2	2.793
34.889689	-78.178956	34.903997	-78.167027	12899.12	3	2.193
34.968100	-78.154200	34.981477	-78.163125	15531.39	3	1.953
34.936100	-78.127400	34.928158	-78.151152	268.61	0.5	2.636
34.945583	-78.156316	34.9681	-78.1542	14086.14	3	2.800
34.928158	-78.151152	34.945583	-78.156316	13871.27	3	2.145
34.903997	-78.167027	34.928158	-78.151152	13132.66	3	3.351
34.852200	-77.969700	34.8483	-77.9492	699.57	1	1.866
34.848300	-77.949200	34.8475	-77.9361	1110.53	1	1.368
34.894400	-77.894400	34.8931	-77.8972	273.98	0.5	0.530
34.899400	-77.928300	34.9131	-77.9531	2949.59	2	3.196
34.843225	-77.886975	34.8475	-77.9361	268.61	0.5	4.863
34.847500	-77.936100	34.8994	-77.9283	1653.13	1	6.072
34.893100	-77.897200	34.8994	-77.9283	976.83	1	3.109
34.876100	-78.023600	34.8872	-77.9781	273.98	0.5	5.539
34.887200	-77.978100	34.9131	-77.9531	1032.36	1	3.890
34.913100	-77.953100	34.93	-77.9367	5702.23	2	2.535

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.947800	-78.036700	34.9544	-78.0214	274.56	0.5	1.772
34.922800	-77.959700	34.9131	-77.9531	1386.03	1	1.243
34.954400	-78.021400	34.9228	-77.9597	752.1	1	7.459

Table F.2.2. Pipeline specification data for Scenario 4, Stage 2 (90 psi)

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.766825	-78.589936	34.759775	-78.674275	3696.32	2	8.526
34.797758	-78.543247	34.766825	-78.589936	3441.14	2	6.121
34.846472	-78.646513	34.759775	-78.674275	410.38	1	10.508
34.819191	-78.544711	34.797758	-78.543247	2640.99	2	2.651
34.838905	-78.531000	34.819191	-78.544711	273.98	0.5	2.949
34.823958	-78.441639	34.797758	-78.543247	252.18	0.5	17.559
35.005394	-78.402063	35.005511	-78.436102	274.2	0.5	3.318
34.918169	-78.313866	34.911742	-78.372683	630.32	1	6.079
34.914686	-78.297930	34.918169	-78.313866	410.96	1	1.617
34.944211	-78.396286	34.939261	-78.420022	1074.43	1	2.532
35.005511	-78.436102	34.947455	-78.45058	649.51	1	6.930
34.939261	-78.420022	34.947455	-78.45058	1403.48	1	2.967
34.911742	-78.372683	34.944211	-78.396286	849.68	1	5.204
34.932667	-78.632761	34.966888	-78.589944	219.36	0.5	5.840
34.947455	-78.450580	34.966888	-78.589944	4718.54	2	16.425
34.994466	-78.586933	34.966888	-78.589944	238.77	0.5	3.305
34.960588	-78.489094	34.947455	-78.45058	238.77	0.5	4.174
35.199114	-78.251505	35.163163	-78.27368	262.64	0.5	4.916
35.144411	-78.263377	35.1556	-78.2658	214.87	0.5	1.475
35.206019	-78.321011	35.179519	-78.358555	1845.45	2	5.505
35.152794	-78.271369	35.1556	-78.2658	270.1	0.5	0.978
35.179519	-78.358555	35.165855	-78.351816	2276.7	2	1.938
35.163163	-78.273680	35.206019	-78.321011	1615.65	1	7.123
35.155600	-78.265800	35.163163	-78.27368	804.61	1	1.429
35.200558	-78.402786	35.18835	-78.402519	686.76	1	1.541
35.155972	-78.400119	35.146044	-78.387802	1226.39	1	2.085
35.216722	-78.415733	35.200558	-78.402786	257.02	0.5	2.985
35.188350	-78.402519	35.155972	-78.400119	928.51	1	3.946
35.096700	-78.368900	35.124116	-78.381274	1089.33	1	3.547
35.047188	-78.302744	35.092269	-78.300733	211.9	0.5	5.527

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.101408	-78.267947	35.092269	-78.300733	219.36	0.5	3.539
35.092269	-78.300733	35.0967	-78.3689	650.61	1	6.657
35.113408	-78.426333	35.134591	-78.4503	223.85	0.5	3.536
35.140816	-78.472502	35.134591	-78.4503	219.36	0.5	2.615
35.134591	-78.450300	35.122205	-78.492827	6420.96	2	4.495
35.124116	-78.381274	35.146044	-78.387802	4294.75	2	2.950
35.165855	-78.351816	35.124116	-78.381274	2967.23	2	5.875
35.146044	-78.387802	35.134591	-78.4503	5749.45	2	6.194
35.152311	-78.373088	35.165855	-78.351816	210.77	0.5	2.576
35.186605	-78.187138	35.23	-78.1722	495.43	1	9.434
35.276700	-78.253300	35.2714	-78.1717	886.38	1	7.704
35.307800	-78.208900	35.3208	-78.2569	214.87	0.5	4.975
35.320800	-78.256900	35.2767	-78.2533	671.51	1	6.967
35.236400	-78.116700	35.2383	-78.1639	966.97	1	4.667
35.230000	-78.172200	35.2383	-78.1639	714.79	1	1.291
35.238300	-78.163900	35.2714	-78.1717	2111.53	2	4.223
35.334700	-78.158100	35.325479	-78.134296	942.71	1	2.810
35.325479	-78.134296	35.2997	-78.1031	1171.02	1	4.542
35.271400	-78.171700	35.2997	-78.1031	3217.26	2	8.703
35.329400	-78.143600	35.3347	-78.1581	214.87	0.5	1.461
35.299400	-78.138100	35.2994	-78.1417	214.87	0.5	0.530
35.299700	-78.103100	35.3064	-78.0678	4947.87	2	4.030
35.299400	-78.141700	35.3347	-78.1581	453.64	1	5.111
35.276200	-77.823617	35.255	-77.822606	537.2	1	2.652
35.245900	-77.795681	35.255	-77.822606	273.98	0.5	2.878
35.255000	-77.822606	35.239506	-77.828245	1079.8	1	1.991
35.288300	-77.838900	35.2762	-77.823617	214.87	0.5	2.291
35.213900	-77.904200	35.1982	-77.81812	214.87	0.5	8.245
35.239506	-77.828245	35.1982	-77.81812	1294.67	1	5.537
35.056900	-77.800300	35.0692	-77.7917	678.2	1	1.840
35.069200	-77.791700	35.1278	-77.7989	1089.16	1	7.133
35.020300	-77.807200	35.0286	-77.7917	248.46	0.5	1.772
35.138100	-77.882500	35.1383	-77.8275	718.1	1	5.564
35.127800	-77.798900	35.1383	-77.8275	1483.11	1	3.429
35.028600	-77.791700	35.0569	-77.8003	463.33	1	3.649
35.126900	-77.896400	35.1381	-77.8825	477.54	1	2.043
35.020800	-77.528300	35.0781	-77.5658	1212.68	1	7.657
34.989400	-77.512500	35.05	-77.4383	277.92	0.5	9.880
35.139400	-77.474400	35.1068	-77.572836	268.61	0.5	10.319
35.078100	-77.565800	35.0781	-77.6528	2662.58	2	8.311

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
35.050000	-77.438300	35.0208	-77.5283	767.49	1	9.373
35.106800	-77.572836	35.0781	-77.5658	746.15	1	3.636
35.138300	-77.827500	35.164538	-77.799262	2439.97	2	4.115
35.206500	-77.785869	35.1793	-77.797182	268.61	0.5	3.252
35.179300	-77.797182	35.1614	-77.68137	5086.61	2	10.573
35.198200	-77.818120	35.1793	-77.797182	1724.41	1	3.001
35.164538	-77.799262	35.1793	-77.797182	2869.74	2	1.890
35.161400	-77.681370	35.1715	-77.66937	8981.8	2	1.777
35.043700	-77.687272	35.0781	-77.6528	335.77	1	5.268
35.171500	-77.669370	35.1817	-77.613714	9223.54	2	5.664
35.078100	-77.652800	35.132	-77.673877	3210.99	2	13.311
35.132000	-77.673877	35.1614	-77.68137	3473.63	2	3.669
34.961700	-77.665000	34.8911	-77.685	797.97	1	8.443
34.926900	-77.625300	34.9617	-77.665	328.31	1	5.735
34.882200	-77.568900	34.8911	-77.685	261.15	0.5	11.851
34.895300	-77.750000	34.8833	-77.7467	314.87	1	1.392
34.891100	-77.685000	34.8833	-77.7467	1287.43	1	6.131
34.883300	-77.819400	34.87	-77.7522	213.38	0.5	6.349
34.883300	-77.746700	34.87	-77.7522	1876.28	2	1.991
34.828300	-77.793600	34.87	-77.7522	214.87	0.5	6.314
34.731900	-77.718100	34.7311	-77.7328	456.61	1	1.577
34.755600	-77.683300	34.7319	-77.7181	228.31	0.5	4.514
34.725000	-77.758300	34.7319	-77.7964	1676.06	1	3.855
34.749700	-77.748100	34.7311	-77.7328	273.98	0.5	2.662
34.731100	-77.732800	34.725	-77.7583	1265.1	1	2.584
34.698100	-77.736400	34.7311	-77.7328	319.63	1	4.563
34.762500	-77.829400	34.7733	-77.8403	262.64	0.5	2.582
34.731900	-77.796400	34.7733	-77.8403	2041.37	1	6.444

Table F.2.3. Pipeline specification data for Scenario 4, Stage 3 (90 psi).

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.747738	-78.231486	34.707683	-78.237938	1546.65	1	4.815
34.725155	-78.333272	34.707683	-78.237938	730.62	1	9.185
34.768025	-78.247361	34.747738	-78.231486	1318.35	1	2.848
34.699461	-78.332383	34.725155	-78.333272	273.98	0.5	3.665
34.807358	-78.299680	34.775663	-78.261705	761.74	1	5.187
34.775663	-78.261705	34.768025	-78.247361	1090.04	1	1.829

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.659743	-78.068863	34.605	-77.9825	3150.25	2	10.990
34.707683	-78.237938	34.688263	-78.180858	2635.43	2	6.181
34.688263	-78.180858	34.659743	-78.068863	2854.79	2	11.455
34.548300	-78.032200	34.605	-77.9825	270.65	0.5	8.323
34.519136	-78.382786	34.524486	-78.474922	373.08	1	8.906
34.524486	-78.474922	34.541061	-78.543486	641.69	1	6.909
34.504702	-78.560475	34.541061	-78.543486	561.1	1	4.762
34.578625	-78.546091	34.592744	-78.56143	1696.13	1	2.331
34.541061	-78.543486	34.578625	-78.546091	1422.15	1	4.620
34.592744	-78.561430	34.58393	-78.599241	1915.49	2	4.036
34.583930	-78.599241	34.637158	-78.689033	2354.21	2	11.571
34.490183	-78.853822	34.4558	-78.8394	328.31	1	4.342
34.416700	-78.691700	34.3569	-78.7339	343.23	1	8.262
34.368100	-78.786100	34.4558	-78.8394	1044.59	1	11.320
34.356900	-78.733900	34.3547	-78.7758	562.59	1	4.168
34.354700	-78.775800	34.3681	-78.7861	781.95	1	1.952
34.455800	-78.839400	34.496205	-78.772841	1635.53	1	7.772
34.628138	-78.722822	34.591611	-78.798319	3136.15	2	8.338
34.534441	-78.715386	34.547755	-78.745588	319.63	1	3.533
34.571938	-78.823838	34.589905	-78.817327	262.64	0.5	2.293
34.589905	-78.817327	34.591611	-78.798319	492.43	1	2.074
34.496205	-78.772841	34.547755	-78.745588	2232.45	2	6.862
34.637158	-78.689033	34.628138	-78.722822	2563.13	2	4.086
34.591611	-78.798319	34.547755	-78.745588	3924.04	2	7.189
34.507897	-79.190111	34.452944	-79.128642	1477.3	1	8.767
34.545250	-79.208794	34.521639	-79.206414	295.46	0.5	3.297
34.513906	-79.228247	34.521639	-79.206414	590.92	1	2.621
34.380206	-79.085872	34.452944	-79.128642	214.87	0.5	9.910
34.521639	-79.206414	34.507897	-79.190111	1181.84	1	2.396
34.484069	-79.228192	34.513906	-79.228247	295.46	0.5	3.538
34.293100	-78.965800	34.2436	-78.8614	3445.19	2	12.160
34.336367	-78.976700	34.2931	-78.9658	3182.55	2	5.524
34.403300	-78.937800	34.336367	-78.9767	2776.65	2	8.935
34.380206	-79.085872	34.4033	-78.9378	2481.19	2	14.845
34.359981	-79.080517	34.380206	-79.085872	493.56	1	2.753
34.871336	-79.302844	34.763285	-79.349904	919.25	1	13.635
34.600053	-79.377925	34.624506	-79.390653	351.88	1	3.244
34.638850	-79.436017	34.624506	-79.390653	558.1	1	4.671
34.693053	-79.342000	34.763285	-79.349904	2879.82	2	9.010
34.624506	-79.390653	34.693053	-79.342	1566.59	1	10.167

Begin Farm		End Farm		Biogas Flow	Pipe Size	Horizontal Distance
Lat	Long	Lat	Long	(CFH)	(inch)	(km)
34.784909	-79.390212	34.763285	-79.349904	346.51	1	6.396
34.692227	-79.466016	34.63885	-79.436017	295.46	0.5	7.844
34.887800	-79.318627	34.871336	-79.302844	590.95	1	2.503
34.746594	-78.956739	34.789342	-79.012822	540.95	1	8.190
34.745044	-78.917589	34.746594	-78.956739	298.46	0.5	3.815
35.169856	-78.690347	35.126086	-78.652589	274.2	0.5	6.908
35.115792	-78.645961	35.188405	-78.575938	1128.53	1	11.696
35.126086	-78.652589	35.115792	-78.645961	603.25	1	1.598
35.422500	-77.768100	35.4125	-77.8058	443.95	1	4.534
35.436400	-77.815300	35.4225	-77.7681	220.1	0.5	4.922
35.412500	-77.805800	35.37	-77.8333	712.56	1	5.774
35.506700	-77.863300	35.504251	-77.821267	1786.94	1	4.366
35.370000	-77.833300	35.4233	-77.8744	1357.2	1	7.107
35.423300	-77.874400	35.5067	-77.8633	1572.07	1	16.714
35.349700	-77.830000	35.37	-77.8333	429.77	1	2.603
35.525800	-77.638900	35.5169	-77.6903	2081.76	2	5.189
35.515800	-77.598900	35.5258	-77.6389	1690.05	1	4.069
35.441100	-77.530600	35.4783	-77.5806	817.08	1	6.612
35.478300	-77.580600	35.4894	-77.6103	1067.77	1	3.180
35.489400	-77.610300	35.5158	-77.5989	1354.28	1	3.197
35.473100	-77.499200	35.4411	-77.5306	497.44	1	5.019
35.485800	-77.495872	35.4731	-77.4992	223.85	0.5	2.394
35.566400	-77.705600	35.5169	-77.6903	279.79	0.5	6.331
35.508300	-77.702800	35.5169	-77.6903	214.87	0.5	1.777
35.516900	-77.690300	35.5317	-77.7403	2848.76	2	5.171
35.531700	-77.740300	35.5114	-77.8	3214.07	2	7.841
35.504251	-77.821267	35.5114	-77.8	2082.4	2	2.124
35.504400	-77.134700	35.5283	-77.174836	322.33	1	5.142
35.521200	-77.250548	35.5283	-77.174836	223.85	0.5	7.585
35.547100	-77.177350	35.5407	-77.170136	322.33	1	1.243
35.528300	-77.174836	35.5407	-77.170136	841.64	1	1.407
35.836700	-76.463300	35.8889	-76.5358	293.23	0.5	10.130
36.373900	-77.104400	36.305346	-77.149872	888.77	1	9.510
36.318100	-77.251400	36.3739	-77.1044	302.32	1	15.407

Appendix G. Modeling Scripts

G.1. Farm Cost Distance Permutation VBA Scripts

```
Private Sub cbboxPlantId_Change()


End Sub


Private Sub cmdCancel_Click()

Unload FrmBiogasPermutation

End Sub


Private Sub cmdOK_Click()

Call eBIOGASPBar_Expand




'Import file management modules


Dim strPWD As String

Dim strScratch As String

Dim costSurface As String

Dim strInputShape As String

Dim TxtResultDir As String

Dim sourceArray(2000) As String

Dim numsource As Integer




strPWD = GetPWD()
```

```
strScratch = strPWD + "\Scratch"

costSurface = strPWD + "\Data\CostSurfaces\costsurf_nc21_nad83_250m.img"

strInputShape = txtPower.value

TxtResultDir = txtOutput.Text


'get the number of rows in the shapefile

Call getSourceList(sourceArray, numsource, strInputShape)

'MsgBox CStr(numSource) + " " + sourceArray(1) + " " + sourceArray(6)


Call CreateFIDArray(strInputShape, "SUM_sum_mm", numsource, strPWD, TxtResultDir) 'create a text document with FACILITY NUMBER & MMBTU

Call CreateCostDistance(strPWD, strScratch, strInputShape, costSurface, numsource, TxtResultDir) 'Call Execute COST_DISTANCE function and export the output into a text document


MsgBox "Operation Completed!"


End Sub


Private Sub getSourceList(ByRef sourArr() As String, ByRef numsource As Integer, ByRef FC As String)

Dim i As Integer

Dim strFieldName As String


Call AddShapeFile(FC)

strFieldName = cbboxPlantId.value


' Create the Geoprocessor object
```

```
Dim GP As Object

'Dim RowCount As Integer

Set GP = CreateObject("esriGeoprocessing.GPDispatch.1")

GP.OverwriteOutput = 1

'check out any necessary licenses

GP.CheckOutExtension "spatial"

' Load required toolboxes...

GP.AddToolbox "C:/Program Files (x86)/ArcGIS/ArcToolbox/Toolboxes/Data Management Tools.tbx"


'Row_Count = "1"

' Process: Get Count...

numsource = GP.GetCount_management(FC)


For i = 1 To numsource


sourArr(i) = "Test" + CStr(i)

Next i


Call deleteLayer(0)

End Sub

Sub CreateFIDArray(ByRef FC As String, ByRef Fld As String, ByRef i As Integer, ByRef strPWD As String,
ByRef strOutputDir As String)


Dim GP As Object ' Create the Geoprocessor object

Set GP = CreateObject("esriGeoprocessing.GPDispatch.1")

GP.OverwriteOutput = 1

GP.CheckOutExtension "spatial" 'check out any necessary licenses
```

```
GP.AddToolbox "C:/Program Files (x86)/ArcGIS/ArcToolbox/Toolboxes/Data Management Tools.tbx" ' Load required toolboxes...




Open strOutputDir + "\FacilityID.inc" For Output As #1 'create a text document for Facility ID

Open strOutputDir + "\mmBTU.inc" For Output As #2 'create a text document for Facility ID and mmBTU of gas generated


Dim recs As IGpEnumObject

Set recs = GP.SearchCursor(FC)


Dim rec As IGpCursorRow

Dim FacilityNumber As String

Dim mmBTU As String

Dim OutLine As String

Set rec = recs.Next()


While Not (rec Is Nothing)

 FacilityNumber = "F" + rec.GetValue("Facility_N") 'acquire facility number, and add character F before the facility numbers

 mmBTU = rec.GetValue("MBTUYR_INT") 'acquire mmbtu

 OutLine = FacilityNumber + " " + mmBTU 'combine facility number and mmbtu into one line with 10 spaces in betwen

 Print #1, CStr(FacilityNumber)

 Print #2, CStr(OutLine)

 Set rec = recs.Next()

Wend

Close #1
```

```
Close #2

End Sub

Sub CreateCostDistance(ByRef strPWD As String, ByRef strScratch, ByRef inFC As String, ByRef costsurf As String, ByRef numsource As Integer, ByRef strOutputDir As String)

Dim GP As Object ' Create the Geoprocessor object
Set GP = CreateObject("esriGeoprocessing.GPDispatch.1")
GP.OverwriteOutput = 1
GP.CheckOutExtension "spatial" 'check out any necessary licenses
GP.AddToolbox "C:/Program Files (x86)/ArcGIS/ArcToolbox/Toolboxes/Spatial Analyst Tools.tbx"
GP.AddToolbox "C:/Program Files (x86)/ArcGIS/ArcToolbox/Toolboxes/Analysis Tools.tbx"
GP.Extent = costsurf
GP.CellSize = costsurf
GP.outputCoordinateSystem = costsurf

Open strOutputDir + "\Routes.inc" For Output As #3 'create a text document for routes between Facility ID and Facility ID
Open strOutputDir + "\RoutesCost.inc" For Output As #4 'create a text document for routes and their costs

' Select selFC (selected Feature Class) and Loop

' Process: Cost Distance...
Dim CDtmp As String
Dim BLtmp As String
```

```
Dim selFCtmp As String
Dim dselFCtmp As String
Dim outFCtmp As String
Dim selExpression As String
Dim dselExpression As String
Dim k As Integer

CDtmp = strScratch + "\CDtmp.img"
BLtmp = strScratch + "\BLtmp.img"
selFCtmp = strScratch + "\selFarm.shp"
dselFCtmp = strScratch + "\dselFarm.shp"
outFCtmp = strScratch + "\EVTPtmp.shp"

Dim recs As IGpEnumObject
Set recs = GP.SearchCursor(inFC)
Dim rec As IGpCursorRow
Set rec = recs.Next()

Dim drecs As IGpEnumObject
Dim drec As IGpCursorRow

Dim Farm1 As String
Dim Farm2 As String
Dim RasterValue As String
Dim Oustr3 As String
Dim Oustr4 As String
```

```
"Call AddShapeFile(inFC)
Dim loopcount As Integer
loopcount = numsource - 1

For k = 0 To loopcount
 FrmBiogasPermutation.label_progress = "Loop Permutation: " & CStr(k + 1) & " of " & CStr(numsource)
 selExpression = """FID""" & " = " & CStr(k)
 dselExpression = """FID""" & " <> " & CStr(k)
 Farm1 = "F" + rec.GetValue("Facility_N")

 GP.Select_analysis inFC, selFCtmp, selExpression
 GP.Select_analysis inFC, dselFCtmp, dselExpression
 GP.CostDistance_sa selFCtmp, costsurf, CDtmp, "", BLtmp
 GP.ExtractValuesToPoints_sa dselFCtmp, CDtmp, outFCtmp, "NONE", "VALUE_ONLY"

 Set drecs = GP.SearchCursor(outFCtmp)
 Set drec = drecs.Next()

 While Not (drec Is Nothing)
 Farm2 = "F" + drec.GetValue("Facility_N")
 RasterValue = drec.GetValue("RASTERVALU") 'acquire rastervalue (cost distance)
 OutStr3 = Farm1 & "." & Farm2 'combine facility number and mmbtu into one line with 10 spaces in betwen
 OutStr4 = Farm1 & "." & Farm2 & " " & RasterValue
 Print #3, CStr(OutStr3)
 Print #4, CStr(OutStr4)
 Set drec = drecs.Next()
 Wend
```

```
 Set rec = recs.Next()

Next k

' Process: Extract Values to Points...

'extract value from cost distance surface by extract value from point
'record points into output text files
'run cost distane using another farm source

Close #3
Close #4

''Call deleteLayer(0)

End Sub

Private Sub cmdSource_Click()
On Error GoTo errorHandler

Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter
Dim str As String
Dim num As Integer
```

```
Dim strList() As String

Filter = 1 'filter shapefile only

Call OpenDialog(str, Filter)



If Len(str) = 0 Then Exit Sub
txtPower.Text = str

Call PopulateField(strList, num, str)

For ii = 1 To num

cbboxPlantId.AddItem strList(ii)

Next ii



Exit Sub
errorHandler:
MsgBox "cmdSource_Click Error. Error No: " + CStr(Err.Number) + " Description :" + Err.Description



End Sub
```

```
Private Sub CommandButton1_Click()
On Error GoTo errorHandler

Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter
Dim str As String
Filter = 1 'filter shapefile only

str = BrowseFolder("Open Output Folder")

If Len(str) = 0 Then Exit Sub
txtOutput.Text = str

Exit Sub
errorHandler:
MsgBox "cmdCarbon_Click Error. Error No: " + CStr(Err.Number) + " Description :" + Err.Description

End Sub


Function GetPWD() As String
 Dim pApp As IApplication
 Set pApp = Application
 Dim VbProject As Object
 Set VbProject = pApp.Document.VbProject
 Dim strInputShape As String
 Dim StrPath, Strshp, strshp2 As String
 Dim kk As Integer
```

```
 strInputShape = VbProject.FileName

 kk = InStrRev(strInputShape, "\")
 GetPWD = VBA.Mid(strInputShape, 1, kk - 1)

End Function

Private Sub label_progress_Click()

End Sub

Private Sub lable_status_Click()

End Sub

Private Sub txtOutput_Change()

End Sub

Private Sub txtPower_Change()

End Sub

Private Sub UserForm_Initialize()
```

```
Dim strSink As String


txtPower.value = "G:\BIOGAS\gis_data\swine_farm_6_Dissolve2_nad83.shp"

txtOutput.value = "G:\BIOGAS\DATA"

Call eBIOGASPBar_reset


End Sub
```

G.2. Equipment Configuration Optimization GAMS Scripts

G.3. Pipeline Model (Scenario 3 and 4)

```
OPTION RESLIM=1000000;
OPTION ITERLIM=1000000;
option OPTCR=0.0;


****************************************/
* Two-Stage Optimization
* OptimaBIOGAS
* This model is designed to map out the most optimal biogas infrastructure
* Duke University
****************************************/
$setglobal data "G:\BIOGAS\MathematicalModeling\DATA\Stage3\Scenario3 \"
$setglobal output2 "G:\BIOGAS\MathematicalModeling\DATA\Stage3\Scenario3 \route\"
$setglobal output "G:\BIOGAS\MathematicalModeling\DATA\Stage3\Scenario3 \route_dev\"

SETS
 Points All Points /
$include %data%FacilityID.inc
 /

 Farms(Points) Farms /
$include %data%Farm_FacilityID.inc
 /

 Hubs(Points) Hubs /
$include %data%Hub_FacilityID.inc
 /
```

```
 Routes(Points, Points) All possible routes between two points /
$include %data%Routes.inc
 /

 Steps /L1*L4/

 StepsK /K1*K4/ ;


PARAMETERS
 FarmGas(Farms) mmBTU of biogas per year from farms
 /
$include %data%Farm_mmBTU.inc
 /

 HubGas(Hubs) mmBTU of biogas per year from hub
 /
$include %data%Hub_mmBTU.inc
 /

 NormCost(Points, Points) Route Cost is the normalized cost by taking account distance and level of
difficulty
 /
$include %data%RoutesCost.inc
 /

 PipeFlow(Steps) unit: CFH
 /
L1 0
L2 300
L3 1828
L4 11157

 /


 PipeSize(Steps) unit: inch
 /
L1 0
L2 0.5
L3 1
L4 2
```

```
 /


 PipeSizeK(StepsK) unit: inch
 /
K1 0
K2 0.5
K3 1
K4 2
 /


 PipeCapitalK(StepsK) unit: dollar per km
 /
K1 0
K2 34575
K3 36075
K4 39354

 /;


ALIAS (Points, Points2, Point);
ALIAS (Farms, Farms2);
ALIAS (Hubs, Hubs2);

SCALAR
 NormCostAdjustment Normalized Cost Adjustment /1000/
 MMBTU_to_CFH Adjust from MMBTU to CFH /0.2021/
 CompressionFactorLow Compression Ratio /7.12/
 WaterLossFactor Gas lost rate for water removal conditioning /0.03/;

Parameter FarmGasCFH(Farms) CFH of biogas per hour from farms;
Parameter HubGasCFH(Hubs) CFH of biogas per hour from hub;
Parameter NormCostKM(Points, Points2);
NormCostKM(Points, Points2) = NormCost(Points,Points2)/NormCostAdjustment;
*NormCost(Points, Points2)$NormCost(Points, Points2)= NormCost(Points,
Points2)/NormCostAdjustment;
FarmGasCFH(Farms)= FarmGas(Farms)* MMBTU_to_CFH / CompressionFactorLow;
HubGasCFH(Hubs) = HubGas(Hubs) * MMBTU_to_CFH / CompressionFactorLow;

DISPLAY Points, Farms, Hubs, Routes, FarmGas, HubGas,FarmGasCFH, HubGasCFH, NormCostKM,
PipeFlow, PipeSize, PipeSizeK ;
```

```
SCALAR
 TimeHorizon years of planning horizon /30/ ;

VARIABLE
 Z total pipeline cost in dollars ;

POSITIVE VARIABLE
 XFlow(Points, Points) amount of biogas transported in CFH
 XSize(Points, Points) pipe size in inches
 XCostPerKm(Points, Points) cost of pipeline development per km in dollars ;

SOS2 VARIABLE
 SepSteps(Points,Points,steps) Separable Programming steps for flow to size
 SepStepsK(Points,Points,stepsK) Separable Programming steps for size to cost ;

EQUATIONS
 COST define objective function
 FLOWING(Farms) flowing equation for each farm
 FLOWTOSIZE(Points, Points) transform capacity to size
 SIZETOCOSTPERKM(Points, Points) transform size to cost per km
 NET_PIPE_FLOW(Points,Points) define pipe Size over separable curve
 NET_PIPE_SIZE(Points,Points) define pipe Size over separable curve
 CONVEX(Points,Points) Convexity Constraint for separable program
 CONVEXK(Points,Points) Convexity Constraint for separable program ;

*---------------
*Objective function
*Pipeline development cost
*---------------
COST ..

Z =E=
SUM((Points, Points2)$Routes(Points, Points2), NormCostKM(Points, Points2)* XCostperkm(Points,
Points2))

;


FLOWING(Farms) ..

*All pipes going to that particular farm
SUM(Farms2$Routes(Farms2,Farms),XFlow(Farms2,Farms))
```

```
*Additional biogas from that farms
+ FarmGasCFH(Farms)*(1-WaterLossFactor)

*Pipe going out to other farms
- Sum(Farms2$Routes(Farms,Farms2),XFlow(Farms,Farms2))

*Pipe going out to hubs
- Sum(Hubs$Routes(Farms,Hubs), XFlow(Farms,Hubs))

=L= 0 ;

*---------------
*Separable programming for flow
*Variable
*---------------
NET_PIPE_FLOW(Points,Points2)..
* XFlow at this point is already determined by FLOWING equation.
* Identify L(x) and L(x+1) and the value of factor of each
XFLOW(Points,Points2) =E=
sum(steps, Sepsteps(Points,Points2,steps) * PipeFlow(steps))
;

*---------------
* Convexity for flow
*---------------
CONVEX(Points,Points2)$Routes(Points,Points2)..
* We make sure the convex combination between two SepSteps is 1
sum(steps, SepSteps(Points,Points2,steps)) =e= 1;


*---------------
* Transforming flow to size
* variable
*---------------

FLOWTOSIZE(Points,Points2)$Routes(Points,Points2) ..

XSize(Points,Points2) =e=
sum(steps, Sepsteps(Points,Points2,steps) * PipeSize(steps))
;

*---------------
* Separable Programming for size
* variable
```

```
*---------------
NET_PIPE_SIZE(Points,Points2)..
* XSIZE at this point is already determined by separable programming
* Identify L(x) and L(x+1) and the value of factor of each
XSIZE(Points,Points2) =E=
sum(stepsK, SepstepsK(Points,Points2,stepsK) * PipeSizeK(stepsK))
;

*---------------
* Convexity for flow
*---------------
CONVEXK(Points,Points2)$routes(Points,Points2)..
* We make sure the convex combination between two SepSteps is 1
sum(stepsK, SepStepsK(Points,Points2,stepsK)) =e= 1;


*---------------
* Transforming size to cost
* variable
*---------------

SIZETOCOSTPERKm(Points,Points2)$Routes(Points,Points2) ..

XCostPerKm(Points,Points2) =e=
sum(stepsK, SepstepsK(Points,Points2,stepsK) * PipeCapitalK(stepsK))
;

MODEL BIOGAS /ALL/ ;
SOLVE BIOGAS USING MIP MINIMIZING Z ;

PARAMETER
CostSegment(Points, Points);
CostSegment(Points, Points2)$XFlow.l(Points, Points2) = XCostPerKm.l(Points,Points2) *
NormCostKM(Points,Points2);



DISPLAY XFlow.l, XSize.l, XCostPerKm.l, CostSegment, Z.l;

*Create discrete pipe size
SET
 DiscPipeSize Discrete Pipe Size /
 Half
 One
```

```
 Two
 Three
 /;

Parameter
UncompFlow(DiscPipeSize)
/
 Half 300
 One 1828
 Two 11157
 Three 31988
/
UncompCost(DiscPipeSize)
/
 Half 34575
 One 36075
 Two 39354
 Three 42571
/

;

VARIABLE
ZPipeDisc Total cost of the discrete pipe system
;
INTEGER VARIABLE
XDiscPipe(Points, Points2, DiscPipeSize) The number of various sizes of pipelines in each segment
;
EQUATIONS
COSTPipe Define objective function
FlowDiscPipe(Points, Points2) Flowing equation
;


*** Objective Function ***
COSTPipe ..
ZPipeDisc =E=
* Conditioning (Capital Cost & OM Discounted Cost)
 SUM((Points, Points2, DiscPipeSize), XDiscPipe(Points, Points2, DiscPipeSize)*
UncompCost(DiscPipeSize))
;

***Capacity constraints***
FlowDiscPipe(Points, Points2) ..
```

```
 XFlow.l(Points,Points2) =L=
SUM((DiscPipeSize),XDiscPipe(Points, Points2, DiscPipeSize)* UncompFlow(DiscPipeSize))
;


MODEL PIPEDISCRETE /
COSTPipe
FlowDiscPipe/;


SOLVE PIPEDISCRETE USING MIP MINIMIZING ZPipeDisc ;

Parameter DiscPipeSegCost(Points, Points2, DiscPipeSize)
 TotalCapitalCost;

DiscPipeSegCost(Points, Points2,DiscPipeSize )$XDiscPipe.l(Points, Points2, DiscPipeSize)=
NormCostKM(Points, Points2) * UncompCost(DiscPipeSize);
TotalCapitalCost = SUM((Points,Points2,DiscPipesize),(DiscPipeSegCost(Points, Points2,
DiscPipeSize))$XDiscPipe.l(Points, Points2, DiscPipeSize));

file Output03 /%output%OutputPipe_s3.txt/;
put Output03;
put "Begin, End, NormCostKM, Mass Flow (CFH), Pipe Size(inches), #Pipe Pipe Cost $/km, Pipe Segment
Cost " /

loop((Points,Points2,DiscPipeSize)$XDiscPipe.l(Points, Points2, DiscPipeSize) ,
 put Points.tl " " Points2.tl " " NormCostKM(Points, Points2) " " XFlow.l(Points,Points2) " " DiscPipeSize.tl
" " XDiscPipe.l(Points, Points2, DiscPipeSize) " " UncompCost(DiscPipeSize) " " DiscPipeSegCost(Points,
Points2,DiscPipeSize )/
);
putclose;

file Output06 /%output%OutputPipe_s3.csv/;
put Output06;
put "Begin, End, NormCostKM, Mass Flow (CFH), Pipe Size(inches), #Pipe Pipe Cost $/km, Pipe Segment
Cost " /

loop((Points,Points2,DiscPipeSize)$XDiscPipe.l(Points, Points2, DiscPipeSize) ,
 put Points.tl "," Points2.tl "," NormCostKM(Points, Points2) "," XFlow.l(Points,Points2) "," DiscPipeSize.tl
"," XDiscPipe.l(Points, Points2, DiscPipeSize) "," UncompCost(DiscPipeSize) "," DiscPipeSegCost(Points,
Points2,DiscPipeSize )/
);
putclose;
display XDiscPipe.l;
```

```
display Uncompflow;

file Output07 /%output%CapitalCost_s3.txt/
put Output07;
put "Total Capital Cost" /
put TotalCapitalCost;
putclose;


file Output01 /%output2%OutputPipe_s3.txt/;
put Output01;

*put /;
*put "Begin, End, NormCostKM, Mass Flow (mtons/year), Pipe Size(inches), Pipe Cost $/km, Pipe Segment
Cost " /

loop((Points,Points2)$(XFlow.l(Points, Points2) GT 0.01) ,
 put Points.tl Points2.tl NormCostKM(Points, Points2) " " XFlow.l(Points,Points2) " "
XSize.l(Points,Points2) " " XCostPerKm.l(Points,Points2) " " CostSegment(Points, Points2)/
);
putclose;

file data05 /%output2%OutputPipe_s3.csv/;
put data05;
put "Begin, End, NormCostKM, Mass Flow (mtons/year), Pipe Size(inches), Pipe Cost $/km, Pipe Segment
Cost " /
loop((Points,Points2)$(XFlow.l(Points, Points2) GT 0.01) ,
 put Points.tl "," Points2.tl "," NormCostKM(Points, Points2) "," XFlow.l(Points,Points2) ","
XSize.l(Points,Points2) "," XCostPerKm.l(Points,Points2) "," CostSegment(Points, Points2)/
);
putclose;
```

G.3.1. Data and Parameter (OptimaBiogas Data V5)

```
SETS
*-----------------------------------------------------
***Hog farms index

 Points All Points /
$include %data%FacilityID.inc
 /

 Farms(Points) Farms /
$include %data%Farm_FacilityID.inc
 /

 Hubs(Points) Hubs /
$include %data%Hub_FacilityID.inc
 /

*-----------------------------------------------------
***Equipment index

 SetsAll All components
 /
$include %data_equipment%Cond_Light_Model.inc
$include %data_equipment%Cond_Heavy_Model.inc
$include %data_equipment%Gen_Engine_Model.inc
$include %data_equipment%Gen_Turbine_Model.inc
 /

 SetsConditioning All possiblte conditioning equipments
 /
$include %data_equipment%Cond_Light_Model.inc
$include %data_equipment%Cond_Heavy_Model.inc
 /

 SetsGenerator All possiblte conditioning equipments
 /
$include %data_equipment%Gen_Engine_Model.inc
$include %data_equipment%Gen_Turbine_Model.inc
 /

 SetsCondLight(SetsConditioning)
 /
$include %data_equipment%Cond_Light_Model.inc
```

```
 /

 SetsCondHeavy(SetsConditioning)
 /
$include %data_equipment%Cond_Heavy_Model.inc
 /

 SetsGenTurbine(SetsGenerator)
 /
$include %data_equipment%Gen_Turbine_Model.inc
 /

 SetsGenEngine(SetsGenerator)
 /
$include %data_equipment%Gen_Engine_Model.inc
 /

 SetsCondWater
 /
$include %data_equipment%Cond_Water_Model.inc
 /

 SetsCompLow
 /
$include %data_equipment%Comp_Low_Model.inc
 /

 SetsTransformer
 /
$include %data_equipment%Transform_Model.inc
 /

 SetsPurifier
 /
$include %data_equipment%Purifier_Model.inc
 /

 SetsCompTwo
 /
$include %data_equipment%Comp_Two_Model.inc
 /

*------------------------------------------------------
***Generator Tupple Sets
```

```
 SetsTupples(SetsConditioning, SetsGenerator );
 SetsTupples(SetsConditioning, SetsGenerator)=Yes;
 SetsTupples(SetsCondLight, SetsGenEngine)=No;


ALIAS (Points, Points2, Point);
ALIAS (Farms, Farms2);
ALIAS (Hubs, Hubs2);

*----------------------------------------------------
SETS
***Discount Rate
SetsYear
/
Year10
Year20
Year30
/;


****************************************************
* Input data and parameters
****************************************************

***Hog farms input data

PARAMETERS

 FarmGas(Farms) mmBTU of biogas per year from farms
 /
$include %data%Farm_mmBTU.inc
 /

 HubGas(Hubs) mmBTU of biogas per year from hub
 /
$include %data%Hub_mmBTU.inc
 /

 PointGas(Points) mmBTU of biogas per year from all points
 /
$include %data%Farm_mmBTU.inc
$include %data%Hub_mmBTU.inc
 /;
```

```
SCALAR
*Assuming 1 cubic feet natural gas contains 1,027 btu of energy
*Assuming biogas contains 50% natural gas (methane)
*0.1111541 / 55% = 0.22
 MMBTU_to_CFH Adjust from MMBTU per year to CFH /0.2021/;


PARAMETER PointGasCFH(Points) CFH of biogas per hour from points;
PointGasCFH(Points) = PointGas(Points) * MMBTU_to_CFH;

PARAMETERS
AmountOfGasmmBTU Total mmBTU of biogas per year from farms and hubs
AmountOfGas Total CFH of biogas from farms and hubs ;
AmountOfGasmmBTU = SUM(Points, PointGas(Points));
AmountOfGas = SUM(Points, PointGasCFH(Points));



***Equipment data

PARAMETERS

*Water removal conditioner

 PCondWaterCapacity(SetsCondWater) CFH - the capacity of water removal conditioning equipment
 /
$include %data_equipment%Cond_Water_Capacity.inc
 /

 PCondWaterCapCost(SetsCondWater) The capital cost of water removal conditioning in dollars
 /
$include %data_equipment%Cond_Water_CapCost.inc
 /

 PCondWaterOMCost(SetsCondWater) The maintenance and operation cost of water removal conditioning
in dollars
 /
$include %data_equipment%Cond_Water_OMCost.inc
 /


*Low pressure compressor
```

PCompLowCapacity(SetsCompLow) CFH - the capacity of low pressure compressor
/
$include %data_equipment%Comp_Low_Capacity.inc
/

PCompLowCapCost(SetsCompLow) The capital cost of low pressure compressor in dollars
/
$include %data_equipment%Comp_Low_CapCost.inc
/

PCompLowOMCost(SetsCompLow) The maintenance and operation cost of low pressure compressor in dollars
/
$include %data_equipment%Comp_Low_OMCost.inc
/

*Conditioning

PCondCapacity(SetsConditioning) CFH - the capacity of conditioning equipment
/
$include %data_equipment%Cond_Light_Capacity.inc
$include %data_equipment%Cond_Heavy_Capacity.inc
/

PCondCapCost(SetsConditioning) The capital cost of conditioning equipment in dollars
/
$include %data_equipment%Cond_Light_CapCost.inc
$include %data_equipment%Cond_Heavy_CapCost.inc
/

PCondOMCost(SetsConditioning) The maintenance and operation cost of conditioning equipment in dollars
/
$include %data_equipment%Cond_Light_OMCost.inc
$include %data_equipment%Cond_Heavy_OMCost.inc
/

*Generator

PGenCapacity(SetsGenerator) CFH - the capacity of generator
/
$include %data_equipment%Gen_Engine_Capacity.inc

```
$include %data_equipment%Gen_Turbine_Capacity.inc
 /

 PGenCapCost(SetsGenerator) The capital cost of generators in dollars
 /
$include %data_equipment%Gen_Engine_CapCost.inc
$include %data_equipment%Gen_Turbine_CapCost.inc
 /

 PGenOMCost(SetsGenerator) The maintenance and operation cost of generators in dollars
 /
$include %data_equipment%Gen_Engine_OMCost.inc
$include %data_equipment%Gen_Turbine_OMCost.inc
 /

 PGenElectricity(SetsGenerator) ekW - electricity generating capacity of generators
 /
$include %data_equipment%Gen_Engine_ekW.inc
$include %data_equipment%Gen_Turbine_ekW.inc
 /


*Transformer

 PTransCapacity(SetsTransformer) kW - the capacity of transformers
 /
$include %data_equipment%Transform_Capacity.inc
 /

 PTransCapCost(SetsTransformer) The capital cost of transformers in dollars
 /
$include %data_equipment%Transform_CapCost.inc
 /

 PTransOMCost(SetsTransformer) The maintenance and operation cost of transformers in dollars
 /
$include %data_equipment%Transform_OMCost.inc
 /


*Conditioner for natural gas pipeline injection

 PPuriCapacity(SetsPurifier) kW - the capacity of NC conditioners
 /
```

```
$include %data_equipment%purifier_Capacity.inc
 /

 PPuriCapCost(SetsPurifier) The capital cost of NC conditioners in dollars
 /
$include %data_equipment%Purifier_CapCost.inc
 /

 PPuriOMCost(SetsPurifier) The maintenance and operation cost of NC conditioners in dollars
 /
$include %data_equipment%Purifier_OMCost.inc
 /


*Two Stage Compressor

 PCompTwoCapacity(SetsCompTwo) kW - the capacity of two stage compressors
 /
$include %data_equipment%Comp_Two_Capacity.inc
 /

 PCompTwoCapCost(SetsCompTwo) The capital cost of two stage compressors in dollars
 /
$include %data_equipment%Comp_Two_CapCost.inc
 /

 PCompTwoOMCost(SetsCompTwo) The maintenance and operation cost of two stage compressors in
dollars
 /
$include %data_equipment%Comp_Two_OMCost.inc
 /

;


***Equipment loss factor


SCALAR
 WaterLossFactor Gas lost rate for water removal conditioning /0.03/
 TransLossFactor Electricity lost rate for voltage transforming /0.03/
 PuriLossFactor_C2 Gas lost rate for purification for scenario 4 /0.44/
 PuriLossFactor_C4 Gas lost rate for purification for scenario 4 /0.39/;
```

```
PARAMETERS
 ConditionLossFactor(SetsConditioning) Gas loss rate for different conditioners
 /
 CondLightFree2000 0
 CondHeavy0 0
 CondHeavyGuildx6000 0.43
 CondHeavyGuildx21000 0.43
 CondHeavyGuildx42000 0.43
 CondHeavyGuildx72000 0.43
 CondHeavyGuildx120000 0.43
 CondHeavyGuildx300000 0.43
 /;


***Calculating O&M cost with discount rate over operating years

SCALAR
* TimeHorizon Years of operation /30/
 r Discount rate /0.07/

;

Parameters
Rate
FinalRate(SetsYear)
ConstantRate
TotalCost(SetsYear)
Year(SetsYear)
/
Year10 10
Year20 20
Year30 30
/;

Rate = 1 / (1 + r);
```

G.3.2. Equipment Model – Scenario 1

```
*************
*OptimaBiogas for Scenario 1
*This model is designed to minimize the cost for each farm based on the data available
*Scenario 1: Each farm collects and genereate electricity at site
```

```
*************


*** <<<<<<<<<<<<<<<<<<<<< MODEL SETUP >>>>>>>>>>>>>>>>>>>>>
*** Solution Tolerance ***
OPTION RESLIM=1000000;
OPTION ITERLIM=1000000;
option OPTCR=0.0;
*** Directories ***
$setglobal data "G:\BIOGAS\MathematicalModeling\DATA\Statewide_sce1\"
$setglobal data_output "G:\BIOGAS\MathematicalModeling\OUTPUT\Statewide_sce1\"
*** Sets, parameters, and scalars setting ***
$setglobal data_equipment "G:\BIOGAS\Programs\Scripts\Data\GAMS_Data_RealData_Sce1\"
$setglobal data_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\"
$include %data_loc%OptimaBiogas_Data_v5_sce1.gms


*** <<<<<<<<<<<<<<<<<<<<<< Cost Optimization for Individual Farms
>>>>>>>>>>>>>>>>>>>>>>
VARIABLE
ZFarm Total cost of the system
;
INTEGER VARIABLE
XCond(Points, SetsConditioning) The number of conditioning equipments
XGen(Points, SetsGenerator) The number of generators
XTrans(Points, SetsTransformer) The number of transformers
;
EQUATIONS
COSTFarm Define objective function
CapacityCond(Points) The capacity of conditioning
CapacityGen(Points, SetsConditioning) The capacity of generator
CapacityTrans(Points) The capacity of transformer
GTOXCond(Points, SetsConditioning) Define positive variable
GTOXGen(Points, SetsGenerator) Define positive variable
GTOXTrans(Points, SetsTransformer) Define pocitive variable
;

*** LCOE Objective Function ***
COSTFarm ..
ZFarm =E=
* Conditioning (Capital Cost & OM Discounted Cost)
 SUM(Points, SUM(SetsConditioning, PCondCapCost(SetsConditioning)*XCond(Points, SetsConditioning)))
+ SUM(Points, SUM(SetsConditioning, (ConstantRate*PCondOMCost(SetsConditioning)*XCond(Points,
SetsConditioning))))
```

```
* Generator (Capital Cost & OM Discounted Cost)
+ SUM(Points, SUM(SetsGenerator, PGenCapCost(SetsGenerator)*XGen(Points, SetsGenerator)))
+ SUM(Points, SUM(SetsGenerator, (ConstantRate*PGenOMCost(SetsGenerator)*XGen(Points,
SetsGenerator))))
* Transformer (Capital Cost & OM Discounted Cost)
+ SUM(Points, SUM(SetsTransformer, PTransCapCost(SetsTransformer)*XTrans(Points, SetsTransformer)))
+ SUM(Points, SUM(SetsTransformer, (ConstantRate*PTransOMCost(SetsTransformer)*XTrans(Points,
SetsTransformer))))
;
***Capacity constraints***
CapacityCond(Points) ..
PointGasCFH(Points) =L=
SUM(SetsConditioning, PCondCapacity(SetsConditioning)*XCond(Points, SetsConditioning))
;
CapacityGen(Points, SetsConditioning) ..
PointGasCFH(Points) * (1-ConditionLossFactor(SetsConditioning)- WaterLossFactor) =L=
SUM(SetsGenerator$SetsTupples(SetsConditioning, SetsGenerator),
PGenCapacity(SetsGenerator)*XGen(Points, SetsGenerator))
;
CapacityTrans(Points) ..
SUM(SetsGenerator, PGenElectricity(SetsGenerator)* XGen(Points, SetsGenerator)) =L=
SUM(SetsTransformer, PTransCapacity(SetsTransformer)*XTrans(Points, SetsTransformer))
;
***Positive decision variable constraints***
*Conditioning units should be greater than zero
GTOXCond(Points, SetsConditioning) .. XCond(Points, SetsConditioning) =G= 0;
*Generator units should be greater than zero
GTOXGen(Points, SetsGenerator) .. XGen(Points, SetsGenerator) =G= 0;
*Transformer units should be greater than zero
GTOXTrans(Points, SetsTransformer) .. XTrans(Points, SetsTransformer) =G= 0;

* Define Model "BIOGASFarm" including 7 equations
MODEL BIOGASFarm /COSTFarm, CapacityCond, CapacityGen, CapacityTrans, GTOXCond,
GTOXGen, GTOXTrans/ ;

PARAMETER
TotalCost(SetsYear) Total cost of all individual farms
SXCond(SetsYear, Points, SetsConditioning) Cond solutions in 3 dimentions
SXGen(SetsYear, Points, SetsGenerator) Gen solutions in 3 dimentions
SXTrans(SetsYear, Points, SetsTransformer) Trans solutions in 3 dimentions

*** <<<<<<<<<<<<<<< Looping by number of years discount >>>>>>>>>>>>>>>>>>>>>
Loop(SetsYear,
*update discount factor for current timeframe
```

```
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
*assgin the na
ConstantRate = FinalRate(SetsYear);
*Solve equations and acquire new solutions
SOLVE BIOGASFarm using MIP MINIMIZING ZFarm;

*assign solved number to sets
TotalCost(SetsYear) = ZFarm.l ;
SXCond(SetsYear, Points, SetsConditioning) = XCond.l(Points, SetsConditioning) ;
SXGen(SetsYear, Points, SetsGenerator) = XGen.l(Points, SetsGenerator) ;
SXTrans(SetsYear, Points, SetsTransformer) = XTrans.l(Points, SetsTransformer);

*DISPLAY XCond.l, XGen.l, XTrans.l, ZFarm.l, TotalCost, SXCond, SXGen, SXTrans;

);




***<<<<<<<<<<<<<<<<<<<<< LCOE & Parameters Calculations >>>>>>>>>>>>>>>>>>>>

SCALAR
OperatingHoursPerYear /8760/
ConversionFactor kWh to mWh /0.001/;

PARAMETERS

FarmCondCapacity(SetsYear,Points) sum of conditioning capacity in a farm
FarmCondRatio(SetsYear,Points,SetsConditioning) ratio of a conditioning unit among all units in a farm
FarmRGenCapacity(SetsYear,Points) loading rate of generators at each farm
FarmElectricity(SetsYear,Points) electricity generated in a farm (ekW per hour)
FarmRGenCapacity(SetsYear,Points) loading rate of the genators in a farm (amount of input gas divided by
sum of gas intake capacity of generators)
FarmActualElectricityPerYear(SetsYear,Points) electricity generated in a farm in a year
ActualElectricityPerYear(SetsYear) sum of electricity generated from a farm
FarmLCOE(SetsYear,Points) levelized cost of electricity for each farm
*for output table
ConditioningCapCost(SetsYear)
GeneratorCapCost(SetsYear)
TransformerCapCost(SetsYear)
ConditioningOMCost(SetsYear)
GeneratorOMCost(SetsYear)
TransformerOMCost(SetsYear)
TCConditioning(SetsYear) Total cost of the conditioning units
```

TCGenerator(SetsYear) Total cost of the generators
TCTransformer(SetsYear) Total cost of the transformers
TCapCost(SetsYear) Total capital cost
TOMCost(SetsYear) Total OM cost

ConditioningCapCostPercent(SetsYear)
GeneratorCapCostPercent(SetsYear)
TransformerCapCostPercent(SetsYear)
TCapCostPercent(SetsYear)

ConditioningOMCostPercent(SetsYear)
GeneratorOMCostPercent(SetsYear)
TransformerOMCostPercent(SetsYear)
TOMCostPercent(SetsYear)

ConditioningTCPercent(SetsYear)
GeneratorTCPercent(SetsYear)
TransformerTCPercent(SetsYear)

LCOE(SetsYear) leveraged cost of electricity for the whole system (cost from ZFarm)
;

FarmCondCapacity(SetsYear,Points) =
SUM(SetsConditioning, PCondCapacity(SetsConditioning)*SXCond(SetsYear,Points,SetsConditioning))
;
FarmCondRatio(SetsYear,Points,SetsConditioning) =

SXCond(SetsYear,Points,SetsConditioning)*PCondCapacity(SetsConditioning)/FarmCondCapacity(SetsYear,
Points)
;
FarmRGenCapacity(SetsYear,Points) =
PointGasCFH(Points)*(1-WaterLossFactor-(SUM(SetsConditioning,
ConditionLossFactor(SetsConditioning)*FarmCondRatio(SetsYear,Points,SetsConditioning))))
/SUM(SetsGenerator, PGenCapacity(SetsGenerator)*SXGen(SetsYear,Points,SetsGenerator))
;
FarmElectricity(SetsYear,Points) =
SUM(SetsGenerator, SXGen(SetsYear,Points,SetsGenerator)*PGenElectricity(SetsGenerator)*(1-
TransLossFactor))
;
FarmActualElectricityPerYear(SetsYear,Points) =
FarmElectricity(SetsYear,Points) * FarmRGenCapacity(SetsYear,Points) * OperatingHoursPerYear *
ConversionFactor
;
FarmLCOE(SetsYear,Points) =

```
*A farm's total capital cost
 (
 SUM(SetsConditioning, PCondCapCost(SetsConditioning)*SXCond(SetsYear,Points,SetsConditioning))
 + SUM(SetsGenerator, PGenCapCost(SetsGenerator)*SXGen(SetsYear,Points,SetsGenerator))
 + SUM(SetsTransformer, PTransCapCost(SetsTransformer)*SXTrans(SetsYear,Points,SetsTransformer))
*A farm's O&M cost
 + SUM(SetsConditioning, (FinalRate(SetsYear) * PCondOMCost(SetsConditioning) *
SXCond(SetsYear,Points,SetsConditioning)))
 + SUM(SetsGenerator, (FinalRate(SetsYear) * PGenOMCost(SetsGenerator) *
SXGen(SetsYear,Points,SetsGenerator)))
 + SUM(SetsTransformer, (FinalRate(SetsYear) * PTransOMCost(SetsTransformer) *
SXTrans(SetsYear,Points,SetsTransformer)))
 )
*total electricity with discount rate
 / (FinalRate(SetsYear)*FarmActualElectricityPerYear(SetsYear,Points))
 ;

ActualElectricityPerYear(SetsYear) =
 SUM(Points, FarmActualElectricityPerYear(SetsYear,Points))
 ;
ConditioningCapCost(SetsYear) =
 SUM(Points, SUM(SetsConditioning,
PCondCapCost(SetsConditioning)*SXCond(SetsYear,Points,SetsConditioning)))
 ;
ConditioningOMCost(SetsYear) =
 SUM(Points, SUM(SetsConditioning,
FinalRate(SetsYear)*PCondOMCost(SetsConditioning)*SXCond(SetsYear,Points,SetsConditioning)))
 ;
TCConditioning(SetsYear) =
 ConditioningCapcost(SetsYear) + ConditioningOMCost(SetsYear)
 ;
GeneratorCapCost(SetsYear) =
 SUM(Points, SUM(SetsGenerator, PGenCapCost(SetsGenerator)*SXGen(SetsYear,Points, SetsGenerator)))
 ;
GeneratorOMCost(SetsYear) =
 SUM(Points, SUM(SetsGenerator,
FinalRate(SetsYear)*PGenOMCost(SetsGenerator)*SXGen(SetsYear,Points, SetsGenerator)))
 ;
TCGenerator(SetsYear) =
 GeneratorCapCost(SetsYear) + GeneratorOMCost(SetsYear)
 ;
TransformerCapCost(SetsYear) =
 SUM(Points, SUM(SetsTransformer, PTransCapCost(SetsTransformer)*SXTrans(SetsYear,Points,
SetsTransformer)))
```

```
 ;
TransformerOMCost(SetsYear) =
 SUM(Points, SUM(SetsTransformer,
FinalRate(SetsYear)*PTransOMCost(SetsTransformer)*SXTrans(SetsYear,Points, SetsTransformer)))
 ;
TCTransformer(SetsYear) =
 TransformerCapCost(SetsYear) + TransformerOMCost(SetsYear)
 ;
***
TCapCost(SetsYear) =
 ConditioningCapCost(SetsYear) + GeneratorCapCost(SetsYear) + TransformerCapCost(SetsYear)
 ;
TOMCost(SetsYear) =
 ConditioningOMCost(SetsYear) + GeneratorOMCost(SetsYear) + TransformerOMCost(SetsYear)
 ;
***
ConditioningCapCostPercent(SetsYear) =
 ConditioningCapCost(SetsYear)/TotalCost(SetsYear)
 ;
GeneratorCapCostPercent(SetsYear) =
 GeneratorCapCost(SetsYear)/TotalCost(SetsYear)
 ;
TransformerCapCostPercent(SetsYear) =
 TransformerCapCost(SetsYear)/TotalCost(SetsYear)
 ;
TCapCostPercent(SetsYear) =

ConditioningCapCostPercent(SetsYear)+GeneratorCapCostPercent(SetsYear)+TransformerCapCostPercent(
SetsYear)
 ;
***
ConditioningOMCostPercent(SetsYear) =
 ConditioningOMCost(SetsYear)/TotalCost(SetsYear)
 ;
GeneratorOMCostPercent(SetsYear) =
 GeneratorOMCost(SetsYear)/TotalCost(SetsYear)
 ;
TransformerOMCostPercent(SetsYear) =
 TransformerOMCost(SetsYear)/TotalCost(SetsYear)
 ;
TOMCostPercent(SetsYear) =

ConditioningOMCostPercent(SetsYear)+GeneratorOMCostPercent(SetsYear)+TransformerOMCostPercent
(SetsYear)
```

```
 ;
***
ConditioningTCPercent(SetsYear) =
 TCConditioning(SetsYear)/TotalCost(SetsYear)
 ;
GeneratorTCPercent(SetsYear) =
 TCGenerator(SetsYear)/TotalCost(SetsYear)
 ;
TransformerTCPercent(SetsYear) =
 TCTransformer(SetsYear)/TotalCost(SetsYear)
 ;

LCOE(SetsYear) =
 TotalCost(SetsYear)
 /
 SUM(Points, FinalRate(SetsYear)* FarmActualElectricityPerYear(SetsYear,Points))
 ;

 DISPLAY FarmCondCapacity, FarmCondRatio, FarmRGenCapacity, FarmElectricity,
 FarmActualElectricityPerYear, ActualElectricityPerYear, FarmLCOE,
 LCOE, TCConditioning, TCGenerator, TCTransformer, XCOND.l, XGEN.l, FinalRate;


***Export modeling results to CSV file

file Output01 /%data_output%OutputBIOGAS_Scenario1_statewide_test.csv/;
put Output01;

***Summary
put "OptimaBiogas Model Report - Scenario 1"/
put "Table 1 - Summary"/
put "TimeFrm," "Equip," "Capital($)," "(%)," "O&M($)," "(%)," "Sum($)," "(%),," "Elec Gen,," "LCOE"/
LOOP(SetsYear,
put Year(SetsYear) ",Conditioning,"
ConditioningCapCost(SetsYear)","ConditioningCapCostPercent(SetsYear)","ConditioningOMCost(SetsYear)
","ConditioningOMCostPercent(SetsYear)","TCConditioning(SetsYear)","ConditioningTCPercent(SetsYear)
/
 ",Generator," GeneratorCapCost(SetsYear) ","
GeneratorCapCostPercent(SetsYear)","GeneratorOMCost(SetsYear)","GeneratorOMCostPercent(SetsYear)"
,"TCGenerator(SetsYear)","GeneratorTCPercent(SetsYear) /
 ",Transformer," TransformerCapCost(SetsYear) ","
TransformerCapCostPercent(SetsYear)","TransformerOMCost(SetsYear)","TransformerOMCostPercent(Set
sYear)","TCTransformer(SetsYear)","TransformerTCPercent(SetsYear) /
```

```
 ",Sum,"
TCapCost(SetsYear)","TCapCostPercent(SetsYear)","TOMCost(SetsYear)","TOMCostPercent(SetsYear)","T
otalCost(SetsYear)",1,,"ActualElectricityPerYear(SetsYear)",mWh,"LCOE(SetsYear)",$/mWh,"/
 /
 )
put /

*** Individual farms
put "Table 2 - Farm Configurations"/
put ",,,,Conditioning,,,,,Generator,,,,,Transformer"/
put
"TimeFrm,FarmID,mmBTUperyear,CFH,Model,Capacity,Number,Capital($),O&M($),Model,Capacity,Numb
er,Capital($),O&M($),Model,Capacity,Number,Capital($),O&M($)"/

loop((SetsYear),
 put Year(SetsYear)","/
 loop((Points),
 put ","Points.tl","PointGas(Points)","PointGasCFH(Points)/

*loop conditioning units
 loop((SetsConditioning)$SXCond(SetsYear,Points,SetsConditioning),
 put
",,,,"SetsConditioning.tl","PCondCapacity(SetsConditioning)","SXCond(SetsYear,Points,SetsConditioning)","
PCondCapCost(SetsConditioning)","PCondOMCost(SetsConditioning) /
 )

*loop generators
 loop((SetsGenerator)$SXGen(SetsYear,Points,SetsGenerator),
 put
",,,,,,,,,"SetsGenerator.tl","PGenCapacity(SetsGenerator)","SXGen(SetsYear,Points,SetsGenerator)","PGenCa
pCost(SetsGenerator)","PGenOMCost(SetsGenerator)/
 )

 );;;
 put /
 );
```

G.3.3. Equipment Model – Scenario 2

```
*************
*OptimaBiogas for Scenario 2
```

```
*This model is designed to minimize the cost for each farm based on the data available
*Scenario 2: Each farm collects and purify biogas on the farm and connects to existing natural gas pipelines
*************

OPTION RESLIM=1000000;
OPTION ITERLIM=1000000;
OPTION OPTCR=0.0;

$setglobal data "G:\BIOGAS\MathematicalModeling\DATA\Stage3\Scenario2\"
$setglobal data_equipment "G:\BIOGAS\Programs\Scripts\Data\GAMS_Data_RealData\"
$Setglobal module_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\Scenario2\"
$setglobal data_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\"
$setglobal data_output "G:\BIOGAS\MathematicalModeling\OUTPUT\Stage3\Scenario2\"

***Sets, parameters, and scalars setting
$include %data_loc%OptimaBiogas_Data_v5.gms



SCALAR
*Input compressed pipeline capital and O&M cost

CompPipe_CapCost Pipeline capital cost /40462449.28/
RPipe /0.40/

CompPipe_OMCost Pipeline O&M cost;
CompPipe_OMCost = CompPipe_CapCost * RPipe;




***Cost optimization for individual farms

*********************************************
***Cost Optimization for Individual Farms
*********************************************

VARIABLE
 ZFarm Total cost of the system
 ;

INTEGER VARIABLE
 XPuri(Points, SetsPurifier) The number of conditioning equipments
```

```
 XCompTwo(Points, SetsCompTwo) The number of generators
 ;

EQUATIONS
 COSTFarm Define objective function
 CapacityPuri(Points) The capacity of conditioning
 CapacityCompTwo(Points) The capacity of generator
 GTOXPuri(Points, SetsPurifier) Define positive variable
 GTOXCompTwo(Points, SetsCompTwo) Define positive variable
 ;


***Objective function

COSTFarm..

ZFarm =E=
* Conditioning for NC pipeline (Capital Cost)
SUM(Points, SUM(SetsPurifier, PPuriCapCost(SetsPurifier)*XPuri(Points, SetsPurifier)))
+
* Conditioning for NC pipeline (O&M Cost & Discount)
SUM(Points, SUM(SetsPurifier, ConstantRate * PPuriOMCost(SetsPurifier)*XPuri(Points, SetsPurifier)))
+
* Two Stage Compressor (Capital Cost)
SUM(Points, SUM(SetsCompTwo, PCompTwoCapCost(SetsCompTwo)*XCompTwo(Points,
SetsCompTwo)))
+
* Two Stage Compressor (O&M Cost & Discount)
SUM(Points, SUM(SetsCompTwo, ConstantRate *
PCompTwoOMCost(SetsCompTwo)*XCompTwo(Points, SetsCompTwo)))

;


***Capacity constraints

*
CapacityPuri(Points) ..
PointGasCFH(Points) =L=
SUM(SetsPurifier, PPuriCapacity(SetsPurifier)*XPuri(Points, SetsPurifier))
;

CapacityCompTwo(Points) ..
PointGasCFH(Points) * (1-PuriLossFactor) =L=
```

```
SUM(SetsCompTwo, PCompTwoCapacity(SetsCompTwo)*XCompTwo(Points, SetsCompTwo))
;


***Positive decision variable constraints

*Conditioning units should be greater than zero
GTOXPuri(Points, SetsPurifier) ..
XPuri(Points, SetsPurifier) =G= 0
;
*Generator units should be greater than zero
GTOXCompTwo(Points, SetsCompTwo) ..
XCompTwo(Points, SetsCompTwo) =G= 0
;


MODEL BIOGASFarm /COSTFarm, CapacityPuri, CapacityCompTwo, GTOXPuri, GTOXCompTwo/ ;
*SOLVE BIOGASFarm USING MIP MINIMIZING ZFarm;

*DISPLAY XPuri.l, XCompTwo.l, ZFarm.l;
PARAMETER
SXPuri(SetsYear, Points, SetsPurifier) Cond solutions in 3 dimentions
SXCompTwo(SetsYear, Points, SetsCompTwo) Gen solutions in 3 dimentions
*SXCompPipe(SetsYear) Trans solutions in 3 dimentions

*** <<<<<<<<<<<<<<<< Looping by number of years discount >>>>>>>>>>>>>>>>>>>>>>>
Loop (SetsYear,
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
ConstantRate = FinalRate(SetsYear);
Solve BIOGASFarm using MIP MINIMIZING ZFarm;

*assign solved number to sets
TotalCost(SetsYear) = ZFarm.l ;
SXPuri(SetsYear, Points, SetsPurifier) = XPuri.l(Points, SetsPurifier) ;
SXCompTwo(SetsYear, Points, SetsCompTwo) = XCompTwo.l(Points, SetsCompTwo) ;
*SXTrans(SetsYear, Points, SetsTransformer) = XTrans.l(Points, SetsTransformer);

) ;

DISPLAY TotalCost, SXPuri, SXCompTwo;
```

```
***LCOE calculation
***<<<<<<<<<<<<<<<<<<<<<< LCOE & Parameters Calculations >>>>>>>>>>>>>>>>>>>>>>

SCALAR
OperatingHoursPerYear /8760/
ConversionFactor kWh to mWh /0.001/
HeatRate mmBTU to mwh /7.2/
NGLossRate NG loss during conditioning and compression /0.075/;

PARAMETERS


ActualNaturalGasPerYear

PuriCapCost(SetsYear)
CompTwoCapCost(SetsYear)
CompPipeCapCost
PuriOMCost(SetsYear)
CompTwoOMCost(SetsYear)
CompPipeOMCost(SetsYear)
TCPuri(SetsYear) Total cost of the conditioning units
TCCompTwo(SetsYear) Total cost of the generators
TCCompPipe(SetsYear) Total cost of the transformers
TCapCost(SetsYear) Total capital cost
TOMCost(SetsYear) Total OM cost
TCostCombine(SetsYear)

PuriCapCostPercent(SetsYear)
CompTwoCapCostPercent(SetsYear)
CompPipeCapCostPercent(SetsYear)
TCapCostPercent(SetsYear)

PuriOMCostPercent(SetsYear)
CompTwoOMCostPercent(SetsYear)
CompPipeOMCostPercent(SetsYear)
TOMCostPercent(SetsYear)

PuriTCPercent(SetsYear)
CompTwoTCPercent(SetsYear)
CompPipeTCPercent(SetsYear)

LCOG(SetsYear) leveraged cost of electricity for the whole system (cost from ZFarm)
LCOE(SetsYear)
 ;
```

```
ActualNaturalGasPerYear = AmountOfGasmmBTU *(1-NGLossRate);

PuriCapCost(SetsYear) =
 SUM(Points, SUM(SetsPurifier, PPuriCapCost(SetsPurifier)*SXPuri(SetsYear,Points,SetsPurifier)))
 ;
PuriOMCost(SetsYear) =
 SUM(Points, SUM(SetsPurifier,
FinalRate(SetsYear)*PPuriOMCost(SetsPurifier)*SXPuri(SetsYear,Points,SetsPurifier)))
 ;
TCPuri(SetsYear) =
 PuriCapCost(SetsYear) + PuriOMCost(SetsYear)
 ;
CompTwoCapCost(SetsYear) =
 SUM(Points, SUM(SetsCompTwo, PCompTwoCapCost(SetsCompTwo)*SXCompTwo(SetsYear,Points,
SetsCompTwo)))
 ;
CompTwoOMCost(SetsYear) =
 SUM(Points, SUM(SetsCompTwo,
FinalRate(SetsYear)*PCompTwoOMCost(SetsCompTwo)*SXCompTwo(SetsYear,Points, SetsCompTwo)))
 ;
TCCompTwo(SetsYear) =
 CompTwoCapCost(SetsYear) + CompTwoOMCost(SetsYear)
 ;

CompPipeCapCost = CompPipe_CapCost;
CompPipeOMCost(SetsYear) = ((Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate))* CompPipe_OMCost


 ;
TCCompPipe(SetsYear) =
 CompPipeCapCost + CompPipeOMCost(SetsYear)
 ;
***
TCapCost(SetsYear) =
 PuriCapCost(SetsYear) + CompTwoCapCost(SetsYear) + CompPipeCapCost
 ;
TOMCost(SetsYear) =
 PuriOMCost(SetsYear) + CompTwoOMCost(SetsYear) + CompPipeOMCost(SetsYear)
 ;
TCostCombine(SetsYear) =
TCapCost(SetsYear)+ TOMCost(SetsYear)
 ;
***
```

```
PuriCapCostPercent(SetsYear) =
 PuriCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoCapCostPercent(SetsYear) =
 CompTwoCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompPipeCapCostPercent(SetsYear) =
 CompPipeCapCost/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
TCapCostPercent(SetsYear) =
 PuriCapCostPercent(SetsYear)+CompTwoCapCostPercent(SetsYear)+CompPipeCapCostPercent(SetsYear)
 ;
***
PuriOMCostPercent(SetsYear) =
 PuriOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoOMCostPercent(SetsYear) =
 CompTwoOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompPipeOMCostPercent(SetsYear) =
 CompPipeOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
TOMCostPercent(SetsYear) =
 PuriOMCostPercent(SetsYear)+CompTwoOMCostPercent(SetsYear)+CompPipeOMCostPercent(SetsYear)
 ;
***
PuriTCPercent(SetsYear) =
 TCPuri(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoTCPercent(SetsYear) =
 TCCompTwo(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompPipeTCPercent(SetsYear) =
 TCCompPipe(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;

LCOG(SetsYear) =
 (TotalCost(SetsYear)+CompPipeCapCost+CompPipeOMCost(SetsYear))
 /
 (FinalRate(SetsYear)* ActualNaturalGasPerYear)
 ;
LCOE(SetsYear) =
 LCOG(SetsYear) * HeatRate
```

```
***Export modeling results to CSV file


file Output01 /%data_output%OutputBIOGAS_Scenario2_stage3.csv/;
put Output01;

***Summary
put "OptimaBiogas Model Report - Scenario 2"/
put "Table 1 - Summary"/
put "TimeFrm," "Equip," "Capital($)," "(%)," "O&M($)," "(%)," "Sum($)," "(%),," "NGas Gen,," "LCOG,," "LCOE"/
LOOP(SetsYear,
put Year(SetsYear) ",Purifier,"
PuriCapCost(SetsYear)","PuriCapCostPercent(SetsYear)","PuriOMCost(SetsYear)","PuriOMCostPercent(SetsYear)","TCPuri(SetsYear)","PuriTCPercent(SetsYear) /
 ",Heavy_Compressor," CompTwoCapCost(SetsYear) ","
CompTwoCapCostPercent(SetsYear)","CompTwoOMCost(SetsYear)","CompTwoOMCostPercent(SetsYear)","TCCompTwo(SetsYear)","CompTwoTCPercent(SetsYear) /
 ",Compressed_Pipeline," CompPipe_CapCost ","
CompPipeCapCostPercent(SetsYear)","CompPipeOMCost(SetsYear)","CompPipeOMCostPercent(SetsYear)","TCCompPipe(SetsYear)","CompPipeTCPercent(SetsYear) /
 ",Sum,"
TCapCost(SetsYear)","TCapCostPercent(SetsYear)","TOMCost(SetsYear)","TOMCostPercent(SetsYear)","TCostCombine(SetsYear)",1,,"ActualNaturalGasPerYear",mmBTU,"LCOG(SetsYear)",$/mmBTU,"LCOE(SetsYear)",$/mwh,"/
 /
 )
put /

*** Individual farms
put "Table 2 - Farm Configurations"/
put ",,,,Purifier,,,,Heavy_Compressor"/
put
"TimeFrm,FarmID,mmBTUperyear,CFH,Capacity,Number,Capital($),O&M($),Capacity,Number,Capital($),O&M($)"/

loop((SetsYear),
 put Year(SetsYear)","/
 loop((Points),
 put ","Points.tl","PointGas(Points)","PointGasCFH(Points)/

*loop purifier units
 loop((SetsPurifier)$SXPuri(SetsYear,Points,SetsPurifier),
```

```
 put
",,,,"PPuriCapacity(SetsPurifier)","SXPuri(SetsYear,Points,SetsPurifier)","PPuriCapCost(SetsPurifier)","PPuri
OMCost(SetsPurifier) /
 );

*loop heavy compressors
 loop((SetsCompTwo)$SXCompTwo(SetsYear,Points,SetsCompTwo),
 put
",,,,,,,"PCompTwoCapacity(SetsCompTwo)","SXCompTwo(SetsYear,Points,SetsCompTwo)","PCompTwoC
apCost(SetsCompTwo)","PCompTwoOMCost(SetsCompTwo)/
 );

 );
 put /
 );
```

G.3.4. Equipment Model – Scenario 3

```
***
* The model is designed to configure the most optimal
* arrangement of component based on the amount of gas available
***

$setglobal data "G:\BIOGAS\MathematicalModeling\DATA\Stage3\Scenario3\grp3k\"
$setglobal data_equipment "G:\BIOGAS\Programs\Scripts\Data\GAMS_Data_RealData\"
$setglobal data_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\"
$setglobal module_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\Scenario3\"
$setglobal data_output "G:\BIOGAS\MathematicalModeling\OUTPUT\Stage3\Scenario3\"


***Sets, parameters, and scalars setting
$include %data_loc%OptimaBiogas_Data_v5.gms

**********************************************
***Cost Optimization for Individual Farms
**********************************************

*////////Notes///////
*Previous version usesd both water removal equipments and low pressure compressors before pipeline
transportation to the hubs.
*With the lack of data of low pressure compressors and the product from water removal equipments is
already 90 psig
*We assume the pressure is enough for local biogas transportation
```

```
*Current solution: use $0 cost for the low pressure compressor to minimize codes modification
*Better solution: remove the low pressure compressor from the codes

VARIABLE
 ZFarm Total cost of the system
 ;
INTEGER VARIABLE
 XCondWater(Points,SetsCondWater) The number of water removal equipments
 XCompLow(Points,SetsCompLow) The number of low pressure compressors
 ;
EQUATIONS
 COSTFarm Define objective function
 CapacityCondWater(Points) The capacity of water removal conditioning
 CapacityCompLow(Points) The capacity of low pressure compressor
 GTOXCondWater(Points,SetsCondWater) Define positive variable
 GTOXCompLow(Points,SetsCompLow) Define positive variable
 ;

***Objective function
COSTFarm ..
ZFarm =E=
* water removal (Capital + OM)
SUM(Points, SUM(SetsCondWater,
PCondWaterCapCost(SetsCondWater)*XCondWater(Points,SetsCondWater)))
+
SUM(Points, SUM(SetsCondWater,
(ConstantRate*PCondWaterOMCost(SetsCondWater)*XCondWater(Points,SetsCondWater))))
+
* low pressure compressor (Capital + OM)
SUM(Poinxxxts, SUM(SetsCompLow,
PCompLowCapCost(SetsCompLow)*XCompLow(Points,SetsCompLow)))
+
SUM(Points, SUM(SetsCompLow,
(ConstantRate*PCompLowOMCost(SetsCompLow)*XCompLow(Points,SetsCompLow))))
;

***Capacity constraints
CapacityCondWater(Points) ..
PointGasCFH(Points) =L= SUM(SetsCondWater,
PCondWaterCapacity(SetsCondWater)*XCondWater(Points,SetsCondWater))
;
CapacityCompLow(Points) ..
PointGasCFH(Points)*(1-WaterLossFactor) =L= SUM(SetsCompLow,
PCompLowCapacity(SetsCompLow)*XCompLow(Points,SetsCompLow))
```

```
;

***Positive decision variable constraints
GTOXCondWater(Points,SetsCondWater) ..
XCondWater(Points,SetsCondWater) =G= 0
;
GTOXCompLow(Points,SetsCompLow) ..
XCompLow(Points,SetsCompLow) =G= 0
;

*Select all equations and constraints for optimization
MODEL BIOGASFarm /COSTFarm, CapacityCondWater, CapacityCompLow, GTOXCondWater,
GTOXCompLow/ ;

*Create parameters to store solution outputs
PARAMETER
FarmTotalCost(SetsYear) Total equipment cost of all farms
SXCondWater(SetsYear, Points, SetsCondWater) CondWater solutions in 3 dimentions
SXCompLow(SetsYear, Points, SetsCompLow) CompLow solutions in 3 dimentions

*Loop through different year span, and solve the equations above
Loop(SetsYear,
*update discount factor for current timeframe
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
*assgin the NPV
ConstantRate = FinalRate(SetsYear);

*Solve equations and acquire new solutions
SOLVE BIOGASFarm USING MIP MINIMIZING ZFarm ;

*Assign solved solutions to sets
FarmTotalCost(SetsYear) = ZFarm.l;
SXCondWater(SetsYear, Points, SetsCondWater) = XCondWater.l(Points,SetsCondWater);
SXCompLow(SetsYear, Points, SetsCompLow) = XCompLow.l(Points,SetsCompLow);

*Display solutions
DISPLAY XCondWater.l, XCompLow.l, ZFarm.l, FarmTotalCost, SXCondwater, SXCompLow;

 );

**********************************************
***Cost Optimization for Hubs
**********************************************
VARIABLE
```

```
 ZHub
 ;
INTEGER VARIABLE
 XCond(SetsConditioning) The number of conditioning equipments
 XGen(SetsGenerator) The number of generators
 XTrans(SetsTransformer)
 ;
EQUATIONS
 COSTHub Define objective function
 CapacityCond The capacity of conditioning
 CapacityGen(SetsConditioning) The capacity of generator
 CapacityTrans The capacity of transformer
 GTOXCond(SetsConditioning) Define positive variable
 GTOXGen(SetsGenerator) Define positive variable
 GTOXTrans(SetsTransformer) Define pocitive variable
 ;

***Objective function

COSTHub ..

ZHub =E=
* Conditioning (Capital + OM)
SUM(SetsConditioning, PCondCapCost(SetsConditioning)*XCond(SetsConditioning))
+
SUM(SetsConditioning, (ConstantRate*PCondOMCost(SetsConditioning)*XCond(SetsConditioning)))
+
* Generator (Capital + OM)
SUM(SetsGenerator, PGenCapCost(SetsGenerator)*XGen(SetsGenerator))
+
SUM(SetsGenerator, (ConstantRate*PGenOMCost(SetsGenerator)*XGen(SetsGenerator)))
+
*Transformer (Capital + OM)
SUM(SetsTransformer, PTransCapCost(SetsTransformer)*XTrans(SetsTransformer))
+
SUM(SetsTransformer, (ConstantRate*PTransOMCost(SetsTransformer)*XTrans(SetsTransformer)))
;

***Capacity constraints
CapacityCond ..
AmountOfGas * (1-WaterLossFactor) =L=
SUM(SetsConditioning, PCondCapacity(SetsConditioning)*XCond(SetsConditioning))
;
CapacityGen(SetsConditioning) ..
```

```
AmountOfGas * (1-WaterLossFactor) * (1-ConditionLossFactor(SetsConditioning)) =L=
SUM(SetsGenerator$SetsTupples(SetsConditioning, SetsGenerator),
PGenCapacity(SetsGenerator)*XGen(SetsGenerator))
;
CapacityTrans ..
SUM(SetsGenerator, PGenElectricity(SetsGenerator)* XGen(SetsGenerator)) =L=
SUM(SetsTransformer, PTransCapacity(SetsTransformer)*XTrans(SetsTransformer))
;

*Positive decision variable constraints
GTOXCond(SetsConditioning) ..
XCond(SetsConditioning) =G= 0
;
GTOXGen(SetsGenerator) ..
XGen(SetsGenerator) =G= 0
;
GTOXTrans(SetsTransformer) ..
XTrans(SetsTransformer) =G= 0
;


MODEL BIOGASHub /COSTHub, CapacityCond, CapacityGen, CapacityTrans, GTOXCond, GTOXGen,
GTOXTrans/ ;

Parameters
HubTotalCost(SetsYear) Total cost in a hub
SXCond(SetsYear, SetsConditioning) Cond solutions in 3 dimentions
SXGen(SetsYear, SetsGenerator) Gen solutions in 3 dimentions
SXTrans(SetsYear, SetsTransformer) Trans solutions in 3 dimentions


Loop(SetsYear,
*update discount factor for current timeframe
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
*assgin the NPV
ConstantRate = FinalRate(SetsYear);

*Solve equations and acquire new solutions
SOLVE BIOGASHub USING MIP MINIMIZING ZHub ;

*Assign solved solutions to sets
HubTotalCost(SetsYear) = ZHub.l;
SXCond(SetsYear, SetsConditioning) = XCond.l(SetsConditioning) ;
SXGen(SetsYear, SetsGenerator) = XGen.l(SetsGenerator) ;
```

```
SXTrans(SetsYear, SetsTransformer) = XTrans.l(SetsTransformer);

DISPLAY XCond.l, XGen.l, XTrans.l, ZHub.l, HubTotalCost, SXCond, SXGen, SXTrans;

 );


SCALAR
*Input pipeline capital and O&M cost
PipeCapCost Pipeline capital cost /1788616.42/
RPipe /0.4/
PipeOMCost Pipeline O&M cost;
PipeOMCost = PipeCapCost * RPipe;


***LCOE calculation***************************************
SCALAR
 OperatingHoursPerYear /8760/
 ConversionFactor kWh to mWh /0.001/;

PARAMETERS
 TotalElectricity(SetsYear) sum of electricity generating capacity from the system (ekW)
 RGenCapacity(SetsYear) loading rate of generators (amount of input gas divided by sum of gas intake
capacity of generators)
 ActualElectricityPerYear(SetsYear) actual amount of electricity generated from the system per year (mWh)
 SUMCondCapacity(SetsYear)

 CondWater_CapCost(SetsYear)
 CondWater_OMCost(SetsYear)
 CompLow_CapCost(SetsYear)
 CompLow_OMCost(SetsYear)
 Cond_CapCost(SetsYear)
 Cond_OMCost(SetsYear)
 Gen_CapCost(SetsYear)
 Gen_OMCost(SetsYear)
 Trans_CapCost(SetsYear)
 Trans_OMCost(SetsYear)
 Pipe_CapCost constant input so no difference between setsyear
 Pipe_OMCost(SetsYear)
 CondWater_TotalCost(SetsYear)
 CompLow_TotalCost(SetsYear)
 Cond_TotalCost(SetsYear)
 Gen_TotalCost(SetsYear)
 Trans_TotalCost(SetsYear)
```

Pipe_TotalCost(SetsYear)
TotalCost_Cap(SetsYear)
TotalCost_OM(SetsYear)
TotalCost(SetsYear)

CondWater_Cap_Ratio(SetsYear)
CondWater_OM_Ratio(SetsYear)
CondWater_Ratio(SetsYear)
CompLow_Cap_Ratio(SetsYear)
CompLow_OM_Ratio(SetsYear)
CompLow_Ratio(SetsYear)
Cond_Cap_Ratio(SetsYear)
Cond_OM_Ratio(SetsYear)
Cond_Ratio(SetsYear)
Gen_Cap_Ratio(SetsYear)
Gen_OM_Ratio(SetsYear)
Gen_Ratio(SetsYear)
Trans_Cap_Ratio(SetsYear)
Trans_OM_Ratio(SetsYear)
Trans_Ratio(SetsYear)
Pipe_Cap_Ratio(SetsYear)
Pipe_OM_Ratio(SetsYear)
Pipe_Ratio(SetsYear)
TotalCost_Cap_Ratio(SetsYear)
TotalCost_OM_Ratio(SetsYear)

LCOE(SetsYear)
denoE(SetsYear)
;

TotalElectricity(SetsYear) = SUM(SetsGenerator,
SXGen(SetsYear,SetsGenerator)*PGenElectricity(SetsGenerator)*(1-TransLossFactor));
SUMCondCapacity(SetsYear) =
SUM(SetsConditioning,SXCond(SetsYear,SetsConditioning)*PCondCapacity(SetsConditioning));
RGenCapacity(SetsYear) = AmountOfGas*(1-WaterLossFactor)*(1-
SUM(SetsConditioning,(ConditionLossFactor(SetsConditioning)*(SXCond(SetsYear,SetsConditioning)*PCon
dCapacity(SetsConditioning)/SUMCondCapacity(SetsYear)))))/(SUM(SetsGenerator,SXGen(SetsYear,SetsGe
nerator)*PGenCapacity(SetsGenerator)));
ActualElectricityPerYear(SetsYear) = TotalElectricity(SetsYear) * RGenCapacity(SetsYear) *
OperatingHoursPerYear * ConversionFactor;

CompPipeOMCost(SetsYear) = ((Rate(1 - (Rate**Year(SetsYear)))) / (1-Rate))* CompPipe_OMCost

*Farm Equipment Cost Calculations

```
 CondWater_CapCost(SetsYear) = SUM(Points, SUM(SetsCondWater,
PCondWaterCapCost(SetsCondWater)*SXCondWater(SetsYear,Points,SetsCondWater)));
 CondWater_OMCost(SetsYear) = SUM(Points, SUM(SetsCondWater,
(FinalRate(SetsYear)*PCondWaterOMCost(SetsCondWater)*SXCondWater(SetsYear,Points,SetsCondWater)
)));
 CompLow_CapCost(SetsYear) = SUM(Points, SUM(SetsCompLow,
PCompLowCapCost(SetsCompLow)*SXCompLow(SetsYear,Points,SetsCompLow)));
 CompLow_OMCost(SetsYear) = SUM(Points, SUM(SetsCompLow,
(FinalRate(SetsYear)*PCompLowOMCost(SetsCompLow)*SXCompLow(SetsYear,Points,SetsCompLow))));
*Hub Equipment Cost Calculations
 Cond_CapCost(SetsYear) = SUM(SetsConditioning,
PCondCapCost(SetsConditioning)*SXCond(SetsYear,SetsConditioning));
 Cond_OMCost(SetsYear) = SUM(SetsConditioning,
(FinalRate(SetsYear)*PCondOMCost(SetsConditioning)*SXCond(SetsYear,SetsConditioning)));
 Gen_CapCost(SetsYear) = SUM(SetsGenerator,
PGenCapCost(SetsGenerator)*SXGen(SetsYear,SetsGenerator));
 Gen_OMCost(SetsYear) = SUM(SetsGenerator,
(FinalRate(SetsYear)*PGenOMCost(SetsGenerator)*SXGen(SetsYear,SetsGenerator)));
 Trans_CapCost(SetsYear) = SUM(SetsTransformer,
PTransCapCost(SetsTransformer)*SXTrans(SetsYear,SetsTransformer));
 Trans_OMCost(SetsYear) = SUM(SetsTransformer,
(FinalRate(SetsYear)*PTransOMCost(SetsTransformer)*SXTrans(SetsYear,SetsTransformer)));
*Pipeline Cost Calculations
 Pipe_CapCost = PipeCapCost;
 Pipe_OMCost(SetsYear) = FinalRate(SetsYear)*PipeOMCost;
*Cost Summary
 CondWater_TotalCost(SetsYear) = CondWater_CapCost(SetsYear) + CondWater_OMCost(SetsYear);
 CompLow_TotalCost(SetsYear) = CompLow_CapCost(SetsYear) + CompLow_OMCost(SetsYear);
 Cond_TotalCost(SetsYear) = Cond_CapCost(SetsYear) + Cond_OMCost(SetsYear);
 Gen_TotalCost(SetsYear) = Gen_CapCost(SetsYear) + Gen_OMCost(SetsYear);
 Trans_TotalCost(SetsYear) = Trans_CapCost(SetsYear) + Trans_OMCost(SetsYear);
 Pipe_TotalCost(SetsYear) = Pipe_CapCost + Pipe_OMCost(SetsYear);

 TotalCost_Cap(SetsYear) = CondWater_CapCost(SetsYear) + CompLow_CapCost(SetsYear)
 + Cond_CapCost(SetsYear) + Gen_CapCost(SetsYear) + Trans_CapCost(SetsYear) + Pipe_CapCost;

 TotalCost_OM(SetsYear) = CondWater_OMCost(SetsYear) + CompLow_OMCost(SetsYear)
 + Cond_OMCost(SetsYear) + Gen_OMCost(SetsYear) + Trans_OMCost(SetsYear) +
Pipe_OMCost(SetsYear);

 TotalCost(SetsYear) = TotalCost_Cap(SetsYear) + TotalCost_OM(SetsYear);

* Cost Percentage Calculations
 CondWater_Cap_Ratio(SetsYear) = CondWater_CapCost(SetsYear)/TotalCost(SetsYear);
```

```
 CondWater_OM_Ratio(SetsYear) = CondWater_OMCost(SetsYear)/TotalCost(SetsYear);
 CondWater_Ratio(SetsYear) = CondWater_TotalCost(SetsYear)/TotalCost(SetsYear);
 CompLow_Cap_Ratio(SetsYear) = CompLow_CapCost(SetsYear)/TotalCost(SetsYear);
 CompLow_OM_Ratio(SetsYear) = CompLow_OMCost(SetsYear)/TotalCost(SetsYear);
 CompLow_Ratio(SetsYear) = CompLow_TotalCost(SetsYear)/TotalCost(SetsYear);
 Cond_Cap_Ratio(SetsYear) = Cond_CapCost(SetsYear)/TotalCost(SetsYear);
 Cond_OM_Ratio(SetsYear) = Cond_OMCost(SetsYear)/TotalCost(SetsYear);
 Cond_Ratio(SetsYear) = Cond_TotalCost(SetsYear)/TotalCost(SetsYear);
 Gen_Cap_Ratio(SetsYear) = Gen_CapCost(SetsYear)/TotalCost(SetsYear);
 Gen_OM_Ratio(SetsYear) = Gen_OMCost(SetsYear)/TotalCost(SetsYear);
 Gen_Ratio(SetsYear) = Gen_TotalCost(SetsYear)/TotalCost(SetsYear);
 Trans_Cap_Ratio(SetsYear) = Trans_CapCost(SetsYear)/TotalCost(SetsYear);
 Trans_OM_Ratio(SetsYear) = Trans_OMCost(SetsYear)/TotalCost(SetsYear);
 Trans_Ratio(SetsYear) = Trans_TotalCost(SetsYear)/TotalCost(SetsYear);
 Pipe_Cap_Ratio(SetsYear) = Pipe_CapCost/TotalCost(SetsYear);
 Pipe_OM_Ratio(SetsYear) = Pipe_OMCost(SetsYear)/TotalCost(SetsYear);
 Pipe_Ratio(SetsYear) = Pipe_TotalCost(SetsYear)/TotalCost(SetsYear);
 TotalCost_Cap_Ratio(SetsYear) = TotalCost_Cap(SetsYear)/TotalCost(SetsYear);
 TotalCost_OM_Ratio(SetsYear) = TotalCost_OM(SetsYear)/TotalCost(SetsYear);

*total electricity with discount rate
 denoE(SetsYear) = FinalRate(SetsYear)* ActualElectricityPerYear(SetsYear);
*Levelised Cost of Electricity
 LCOE(SetsYear) = TotalCost(SetsYear) / denoE(SetsYear);
 ;


DISPLAY TotalElectricity, RGenCapacity, ActualElectricityPerYear, RGenCapacity, LCOE, PipeOMCost,
denoE;


***Export modeling results to CSV file

file Output01 /%data_output%OutputBIOGAS_Scenario3_grp3k.csv/;
put Output01;

***Summary
put "OptimaBiogas Model Report - Scenario 3"/
put "Table 1 - Summary"/
put "TimeFrm," "Equip," "Capital($)," "(%)," "O&M($)," "(%)," "Sum($)," "(%),," "Elec Gen,," "LCOE"/
LOOP(SetsYear,
put Year(SetsYear) ",WaterRemoval,"
CondWater_CapCost(SetsYear)","CondWater_Cap_Ratio(SetsYear)","CondWater_OMCost(SetsYear)","Con
dWater_OM_Ratio(SetsYear)","CondWater_TotalCost(SetsYear)","CondWater_Ratio(SetsYear) /
```

```
 ",LowCompressor,"
CompLow_CapCost(SetsYear)","CompLow_Cap_Ratio(SetsYear)","CompLow_OMCost(SetsYear)","Comp
Low_OM_Ratio(SetsYear)","CompLow_TotalCost(SetsYear)","CompLow_Ratio(SetsYear) /
 ",Conditioning,"
Cond_CapCost(SetsYear)","Cond_Cap_Ratio(SetsYear)","Cond_OMCost(SetsYear)","Cond_OM_Ratio(Sets
Year)","Cond_TotalCost(SetsYear)","Cond_Ratio(SetsYear) /
 ",Generator," Gen_CapCost(SetsYear) ","
Gen_Cap_Ratio(SetsYear)","Gen_OMCost(SetsYear)","Gen_OM_Ratio(SetsYear)","Gen_TotalCost(SetsYe
ar)","Gen_Ratio(SetsYear) /
 ",Transformer," Trans_CapCost(SetsYear) ","
Trans_Cap_Ratio(SetsYear)","Trans_OMCost(SetsYear)","Trans_OM_Ratio(SetsYear)","Trans_TotalCost(S
etsYear)","Trans_Ratio(SetsYear) /
 ",Pipeline," Pipe_CapCost ","
Pipe_Cap_Ratio(SetsYear)","Pipe_OMCost(SetsYear)","Pipe_OM_Ratio(SetsYear)","Pipe_TotalCost(SetsYe
ar)","Pipe_Ratio(SetsYear) /
 ",Sum,"
TotalCost_Cap(SetsYear)","TotalCost_Cap_Ratio(SetsYear)","TotalCost_OM(SetsYear)","TotalCost_OM_R
atio(SetsYear)","TotalCost(SetsYear)",1,,"ActualElectricityPerYear(SetsYear)",mWh,"LCOE(SetsYear)",$/m
Wh," /
 /
 )
put /



*** Individual farms
put "Table 2 - Hub Configurations"/
put ",,,,Conditioning,,,,,Generator,,,,,Transformer"/
put
"TimeFrm,HubID,mmBTUperyear,CFH,Model,Capacity,Number,Capital($),O&M($),Model,Capacity,Numb
er,Capital($),O&M($),Model,Capacity,Number,Capital($),O&M($)"/

loop((SetsYear),
 put Year(SetsYear)","/
 loop((Hubs),
* now we only have 1 hub, if more thant one, we need to change AmmountOfGasmmBTU and
AmountOfGas
 put ","Hubs.tl","AmountOfGasmmBTU","AmountOfGas/

*loop conditioning units
 loop((SetsConditioning)$SXCond(SetsYear,SetsConditioning),
 put
",,,,"SetsConditioning.tl","PCondCapacity(SetsConditioning)","SXCond(SetsYear,SetsConditioning)","PCond
CapCost(SetsConditioning)","PCondOMCost(SetsConditioning) /
```

```
 );
*loop generators
 loop((SetsGenerator)$SXGen(SetsYear,SetsGenerator),
 put
",,,,,,,,"SetsGenerator.tl","PGenCapacity(SetsGenerator)","SXGen(SetsYear,SetsGenerator)","PGenCapCost(
SetsGenerator)","PGenOMCost(SetsGenerator)/
 );
*loop transformer
 loop((SetsTransformer)$SXTrans(SetsYear,SetsTransformer),
 put
",,,,,,,,,,,,"SetsTransformer.tl","PTransCapacity(SetsTransformer)","SXTrans(SetsYear,SetsTransformer)","P
TransCapCost(SetsTransformer)","PTransOMCost(SetsTransformer)/
 );

 );
 put /
 );


*** Individual farms
put "Table 3 - Farm Configurations"/
put ",,,,WaterRemoval,,,,,LighCompressor"/
put
"TimeFrm,FarmID,mmBTUperyear,CFH,Model,Capacity,Number,Capital($),O&M($),Model,Capacity,Numb
er,Capital($),O&M($)"/

loop((SetsYear),
 put Year(SetsYear)","/
 loop((Points),
 put ","Points.tl","PointGas(Points)","PointGasCFH(Points)/

*loop water removal units
 loop((SetsCondWater)$SXCondWater(SetsYear,Points,SetsCondWater),
 put
",,,,"SetsCondWater.tl","PCondWaterCapacity(SetsCondWater)","SXCondWater(SetsYear,Points,SetsCondW
ater)","PCondWaterCapCost(SetsCondWater)","PCondWaterOMCost(SetsCondWater) /
 );

*loop low compressor units
 loop((SetsCompLow)$SXCompLow(SetsYear,Points,SetsCompLow),
 put
",,,,,,,,,"SetsCompLow.tl","PCompLowCapacity(SetsCompLow)","SXCompLow(SetsYear,Points,SetsCompL
ow)","PCompLowCapCost(SetsCompLow)","PCompLowOMCost(SetsCompLow)/
 );
```

```
*loop transformer

 );
 put /
 );
```

G.3.5. Equipment Model – Scenario 4

```
***
* The model is designed to configure the most optimal
* arrangement of component based on the amount of gas available
***

$setglobal data "G:\BIOGAS\MathematicalModeling\DATA\Scenario4\GAMS_EQ_INPUT\c4_grp1f\"
$setglobal data_equipment "G:\BIOGAS\Programs\Scripts\Data\GAMS_Data_RealData\"
$setGlobal data_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\"
$setglobal module_loc "G:\BIOGAS\MathematicalModeling\OptimaBIOGAS_Module\Scenario4\"
$setglobal data_output "G:\BIOGAS\MathematicalModeling\OUTPUT\Scenario4_Stage1\"




***Sets, parameters, and scalars setting
$include %data_loc%OptimaBiogas_Data_v5.gms

*********************************************
***Cost Optimization for Individual Farms
*********************************************


VARIABLE
 ZFarm Total cost of the system ;

INTEGER VARIABLE
 XCondWater(Farms,SetsCondWater) The number of water removal equipments
 XCompLow(Farms,SetsCompLow) The number of low pressure compressors ;

EQUATIONS
 COSTFarm Define objective function
 CapacityCondWater(Farms) The capacity of water removal conditioning
 CapacityCompLow(Farms) The capacity of low pressure compressor
 GTOXCondWater(Farms,SetsCondWater) Define positive variable
```

```
 GTOXCompLow(Farms,SetsCompLow) Define positive variable

 ;

***Objective function

COSTFarm ..

ZFarm =E=

* water removal
SUM(Farms, SUM(SetsCondWater,
PCondWaterCapCost(SetsCondWater)*XCondWater(Farms,SetsCondWater)))
+

SUM(Farms, SUM(SetsCondWater,
(ConstantRate*PCondWaterOMCost(SetsCondWater)*XCondWater(Farms,SetsCondWater))))
+

* low pressure compressor
SUM(Farms, SUM(SetsCompLow,
PCompLowCapCost(SetsCompLow)*XCompLow(Farms,SetsCompLow)))
+

SUM(Farms, SUM(SetsCompLow,
(ConstantRate*PCompLowOMCost(SetsCompLow)*XCompLow(Farms,SetsCompLow))))

;

***Capacity constraints

CapacityCondWater(Farms) ..

PointGasCFH(Farms) =L=
SUM(SetsCondWater, PCondWaterCapacity(SetsCondWater)*XCondWater(Farms,SetsCondWater))
;

CapacityCompLow(Farms) ..

PointGasCFH(Farms)*(1-WaterLossFactor) =L=
SUM(SetsCompLow, PCompLowCapacity(SetsCompLow)*XCompLow(Farms,SetsCompLow))
;
```

```
***Positive decision variable constraints

GTOXCondWater(Farms,SetsCondWater) ..

XCondWater(Farms,SetsCondWater) =G= 0
;

GTOXCompLow(Farms,SetsCompLow) ..

XCompLow(Farms,SetsCompLow) =G= 0
;



MODEL BIOGASFarm /COSTFarm, CapacityCondWater, CapacityCompLow, GTOXCondWater,
GTOXCompLow/ ;


*DISPLAY XPuri.l, XCompTwo.l, ZFarm.l;
PARAMETER
SXCondWater(SetsYear, Farms, SetsCondWater) Cond solutions in 3 dimentions
SXCompLow(SetsYear, Farms, SetsCompLow) Gen solutions in 3 dimentions
*SXCompPipe(SetsYear) Trans solutions in 3 dimentions

*** <<<<<<<<<<<<<<< Looping by number of years discount >>>>>>>>>>>>>>>>>>>>>>
Loop (SetsYear,
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
ConstantRate = FinalRate(SetsYear);
Solve BIOGASFarm using MIP MINIMIZING ZFarm;

*assign solved number to sets
TotalCostFarm(SetsYear) = ZFarm.l ;
SXCondWater(SetsYear, Farms, SetsCondWater) = XCondWater.l(Farms, SetsCondWater) ;
SXCompLow(SetsYear, Farms, SetsCompLow) = XCompLow.l(Farms, SetsCompLow) ;
*SXTrans(SetsYear, Points, SetsTransformer) = XTrans.l(Points, SetsTransformer);

) ;

DISPLAY TotalCostFarm, SXCondWater, SXCompLow;

*********************************************
***Cost Optimization for Hubs
*********************************************
VARIABLE
```

```
 ZHub ;

INTEGER VARIABLE
 XPuri(SetsPurifier) The number of conditioning equipments
 XCompTwo(SetsCompTwo) The number of generators
* XTrans(SetsTransformer);

EQUATIONS
 COSTHub Define objective function
 CapacityPuri The capacity of conditioning
 CapacityCompTwo The capacity of generator
* CapacityTrans The capacity of transformer
 GTOXPuri(SetsPurifier) Define positive variable
 GTOXCompTwo(SetsCompTwo) Define positive variable
* GTOXTrans(SetsTransformer) Define pocitive variable

 ;

***Objective function

COSTHub ..

ZHub =E=
* purifier
SUM(SetsPurifier, PPuriCapCost(SetsPurifier)*XPuri(SetsPurifier))
+

SUM(SetsPurifier, (ConstantRate*PPuriOMCost(SetsPurifier)*XPuri(SetsPurifier)))
+

* two stage compressor
SUM(SetsCompTwo, PCompTwoCapCost(SetsCompTwo)*XCompTwo(SetsCompTwo))
+

SUM(SetsCompTwo, (ConstantRate*PCompTwoOMCost(SetsCompTwo)*XCompTwo(SetsCompTwo)))
*+

*transformer
*SUM(SetsTransformer, PTransCapCost(SetsTransformer)*XTrans(SetsTransformer))
*+

*SUM(SetsYear, SUM(SetsTransformer,
((1/((1+r)**(Year(SetsYear))))*PTransOMCost(SetsTransformer)*XTrans(SetsTransformer))))
```

```
;

***Capacity constraints

CapacityPuri ..

AmountOfGas * (1-WaterLossFactor) =L=
SUM(SetsPurifier, PPuriCapacity(SetsPurifier)*XPuri(SetsPurifier))
;

CapacityCompTwo ..

AmountOfGas * (1-WaterLossFactor) *(1-PuriLossFactor) =L=
SUM(SetsCompTwo, PCompTwoCapacity(SetsCompTwo)*XCompTwo(SetsCompTwo))
;

*CapacityTrans ..

*SUM(SetsGenerator, PGenElectricity(SetsGenerator)* XGen(SetsGenerator)) =L=
*SUM(SetsTransformer, PTransCapacity(SetsTransformer)*XTrans(SetsTransformer))
*;

*Positive decision variable constraints

GTOXPuri(SetsPurifier) ..

XPuri(SetsPurifier) =G= 0
;

GTOXCompTwo(SetsCompTwo) ..

XCompTwo(SetsCompTwo) =G= 0
;

*GTOXTrans(SetsTransformer) ..

*XTrans(SetsTransformer) =G= 0
*;


MODEL BIOGASHub /COSTHub, CapacityPuri, CapacityCompTwo, GTOXPuri, GTOXCompTwo/ ;


*DISPLAY XPuri.l, XCompTwo.l, ZFarm.l;
```

```
PARAMETER
SXPuri(SetsYear, SetsPurifier) Cond solutions in 3 dimentions
SXCompTwo(SetsYear, SetsCompTwo) Gen solutions in 3 dimentions
*SXCompPipe(SetsYear) Trans solutions in 3 dimentions

*** <<<<<<<<<<<<<<<< Looping by number of years discount >>>>>>>>>>>>>>>>>>>>>>
Loop (SetsYear,
FinalRate(SetsYear) = (Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate);
ConstantRate = FinalRate(SetsYear);
Solve BIOGASHub using MIP MINIMIZING ZHub;

*assign solved number to sets
TotalCostHub(SetsYear) = ZHub.l ;
SXPuri(SetsYear, SetsPurifier) = XPuri.l(SetsPurifier) ;
SXCompTwo(SetsYear, SetsCompTwo) = XCompTwo.l(SetsCompTwo) ;
*SXTrans(SetsYear, Points, SetsTransformer) = XTrans.l(Points, SetsTransformer);

) ;

DISPLAY TotalCostHub, SXPuri, SXCompTwo;

SCALAR
*Input pipeline capital and O&M cost

Pipe_CapCost Pipeline capital cost /449458/
CompPipe_CapCost Compressed pipeline capital cost /55443/
RPipe /0.40/
Pipe_OMCost Pipeline O&M cost
CompPipe_OMCost Compressed pipeline O&M cost;
Pipe_OMCost = Pipe_CapCost * RPipe;
CompPipe_OMCost = CompPipe_CapCost * RPipe;


***<<<<<<<<<<<<<<<<<<<<<< LCOE & Parameters Calculations >>>>>>>>>>>>>>>>>>>>

SCALAR
OperatingHoursPerYear /8760/
ConversionFactor kWh to mWh /0.001/
HeatRate mmBTU to mwh /7.2/
NGLossRate NG loss during conditioning and compression /0.075/;

PARAMETERS
```

ActualNaturalGasPerYear

CondWaterCapCost(SetsYear)
CompLowCapCost(SetsYear)
PipeCapCost
PuriCapCost(SetsYear)
CompTwoCapCost(SetsYear)
CompPipeCapCost

CondWaterOMCost(SetsYear)
CompLowOMCost(SetsYear)
PipeOMCost
PuriOMCost(SetsYear)
CompTwoOMCost(SetsYear)
CompPipeOMCost(SetsYear)

TCCondWater(SetsYear)
TCCompLow(SetsYear)
TCPipe(SetsYear)
TCPuri(SetsYear) Total cost of the purification units
TCCompTwo(SetsYear) Total cost of the compressor
TCCompPipe(SetsYear) Total cost of the compressed pipeline

TCapCost(SetsYear) Total capital cost
TOMCost(SetsYear) Total OM cost
TotalCostCombine(SetsYear)

CondWaterCapCostPercent(SetsYear)
CompLowCapCostPercent(SetsYear)
PipeCapCostPercent(SetsYear)
PuriCapCostPercent(SetsYear)
CompTwoCapCostPercent(SetsYear)
CompPipeCapCostPercent(SetsYear)
TCapCostPercent(SetsYear)

CondWaterOMCostPercent(SetsYear)
CompLowOMCostPercent(SetsYear)
PipeOMCostPercent(SetsYear)
PuriOMCostPercent(SetsYear)
CompTwoOMCostPercent(SetsYear)
CompPipeOMCostPercent(SetsYear)
TOMCostPercent(SetsYear)

CondWaterTCPercent(SetsYear)

```
CompLowTCPercent(SetsYear)
PipeTCPercent(SetsYear)
PuriTCPercent(SetsYear)
CompTwoTCPercent(SetsYear)
CompPipeTCPercent(SetsYear)

LCOG(SetsYear) leveraged cost of electricity for the whole system (cost from ZFarm)
LCOE(SetsYear)
 ;

ActualNaturalGasPerYear = AmountOfGasmmBTU *(1-NGLossRate);

CondWaterCapCost(SetsYear) =
 SUM(Farms, SUM(SetsCondWater, PCondWaterCapCost(SetsCondWater)*SXCondWater(SetsYear, Farms,
SetsCondWater)))
 ;
CondWaterOMCost(SetsYear) =
 SUM(Farms, SUM(SetsCondWater,
FinalRate(SetsYear)*PCondWaterOMCost(SetsCondWater)*SXCondWater(SetsYear, Farms,
SetsCondWater)))
 ;
TCCondWater(SetsYear) =
 CondWaterCapCost(SetsYear) + CondWaterOMCost(SetsYear)
 ;
CompLowCapCost(SetsYear) =
 SUM(Farms, SUM(SetsCompLow, PCompLowCapCost(SetsCompLow)*SXCompLow(SetsYear, Farms,
SetsCompLow)))
 ;
CompLowOMCost(SetsYear) =
 SUM(Farms, SUM(SetsCompLow,
FinalRate(SetsYear)*PCompLowOMCost(SetsCompLow)*SXCompLow(SetsYear, Farms, SetsCompLow)))
 ;
TCCompLow(SetsYear) =
 CompLowCapCost(SetsYear) + CompLowOMCost(SetsYear)
 ;

PipeCapCost = Pipe_CapCost;
PipeOMCost(SetsYear) = ((Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate))* Pipe_OMCost
 ;
TCPipe(SetsYear) =
 PipeCapCost + PipeOMCost(SetsYear)
 ;

PuriCapCost(SetsYear) =
```

```
 SUM(SetsPurifier, PPuriCapCost(SetsPurifier)*SXPuri(SetsYear,SetsPurifier))
 ;
PuriOMCost(SetsYear) =
 SUM(SetsPurifier, FinalRate(SetsYear)*PPuriOMCost(SetsPurifier)*SXPuri(SetsYear,SetsPurifier))
 ;
TCPuri(SetsYear) =
 PuriCapCost(SetsYear) + PuriOMCost(SetsYear)
 ;
CompTwoCapCost(SetsYear) =
 SUM(SetsCompTwo, PCompTwoCapCost(SetsCompTwo)*SXCompTwo(SetsYear, SetsCompTwo))
 ;
CompTwoOMCost(SetsYear) =
 SUM(SetsCompTwo, FinalRate(SetsYear)*PCompTwoOMCost(SetsCompTwo)*SXCompTwo(SetsYear,
SetsCompTwo))
 ;
TCCompTwo(SetsYear) =
 CompTwoCapCost(SetsYear) + CompTwoOMCost(SetsYear)
 ;

CompPipeCapCost = CompPipe_CapCost;
CompPipeOMCost(SetsYear) = ((Rate*(1 - (Rate**Year(SetsYear)))) / (1-Rate))* CompPipe_OMCost
 ;
TCCompPipe(SetsYear) =
 CompPipeCapCost + CompPipeOMCost(SetsYear)
 ;
***
TCapCost(SetsYear) =
 PuriCapCost(SetsYear) + CompTwoCapCost(SetsYear) + CompPipeCapCost
 + CondWaterCapCost(SetsYear) + CompLowCapCost(SetsYear) + PipeCapCost
 ;
TOMCost(SetsYear) =
 PuriOMCost(SetsYear) + CompTwoOMCost(SetsYear) + CompPipeOMCost(SetsYear)
 + CondWaterOMCost(SetsYear) + CompLowOMCost(SetsYear) + PipeOMCost(SetsYear)
 ;
TotalCostCombine(SetsYear) =
 TCapCost(SetsYear) + TOMCost(SetsYear)
 ;
***
PuriCapCostPercent(SetsYear) =
 PuriCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoCapCostPercent(SetsYear) =
 CompTwoCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
```

CompPipeCapCostPercent(SetsYear) =
 CompPipeCapCost/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CondWaterCapCostPercent(SetsYear) =
 CondWaterCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompLowCapCostPercent(SetsYear) =
 CompLowCapCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
PipeCapCostPercent(SetsYear) =
 PipeCapCost/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
TCapCostPercent(SetsYear) =
 PuriCapCostPercent(SetsYear)+CompTwoCapCostPercent(SetsYear)+CompPipeCapCostPercent(SetsYear)
 +
CondWaterCapCostPercent(SetsYear)+CompLowCapCostPercent(SetsYear)+PipeCapCostPercent(SetsYear)
 ;
***
PuriOMCostPercent(SetsYear) =
 PuriOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoOMCostPercent(SetsYear) =
 CompTwoOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompPipeOMCostPercent(SetsYear) =
 CompPipeOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CondWaterOMCostPercent(SetsYear) =
 CondWaterOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompLowOMCostPercent(SetsYear) =
 CompLowOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
PipeOMCostPercent(SetsYear) =
 PipeOMCost(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
TOMCostPercent(SetsYear) =
 PuriOMCostPercent(SetsYear)+CompTwoOMCostPercent(SetsYear)+CompPipeOMCostPercent(SetsYear)
 +
CondWaterOMCostPercent(SetsYear)+CompLowOMCostPercent(SetsYear)+PipeOMCostPercent(SetsYear
)
 ;
***
PuriTCPercent(SetsYear) =

```
 TCPuri(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompTwoTCPercent(SetsYear) =
 TCCompTwo(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompPipeTCPercent(SetsYear) =
 TCCompPipe(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CondWaterTCPercent(SetsYear) =
 TCCondWater(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
CompLowTCPercent(SetsYear) =
 TCCompLow(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;
PipeTCPercent(SetsYear) =
 TCPipe(SetsYear)/(TCapCost(SetsYear)+TOMCost(SetsYear))
 ;

LCOG(SetsYear) =
 (TotalCostFarm(SetsYear)+TotalCostHub(SetsYear)+TCCompPipe(SetsYear)+TCPipe(SetsYear))
 /
 (FinalRate(SetsYear)* ActualNaturalGasPerYear)
 ;
LCOE(SetsYear) =
 LCOG(SetsYear) * HeatRate
* DISPLAY FarmCondCapacity, FarmCondRatio, FarmRGenCapacity, FarmElectricity,
* FarmActualElectricityPerYear, ActualElectricityPerYear, FarmLCOE,
* LCOE, TCConditioning, TCGenerator, TCTransformer;

*LCOG =
* (ZFarm.L + (CompPipeCapCost + SUM(SetsYear,(1/((1+r)**(Year(SetsYear))))*CompPipeOMCost)))
* / (SUM(SetsYear,(1/((1+r)**(Year(SetsYear))))* ActualNaturalGasPerYear))
* ;

***Export modeling results to CSV file


file Output01 /%data_output%OutputBIOGAS_Scenario4_grp1f_test.csv/;
put Output01;

***Summary
put "OptimaBiogas Model Report - Scenario 4"/
put "Table 1 - Summary"/
```

```
put "TimeFrm," "Equip," "Capital($)," "(%)," "O&M($)," "(%)," "Sum($)," "(%),," "NGas Gen,," "LCOG,,"
"LCOE"/
LOOP(SetsYear,
put Year(SetsYear) ",Water_Removal,"
CondWaterCapCost(SetsYear)","CondWaterCapCostPercent(SetsYear)","CondWaterOMCost(SetsYear)","C
ondWaterOMCostPercent(SetsYear)","TCCondWater(SetsYear)","CondWaterTCPercent(SetsYear) /
 ",Light_Compressor," CompLowCapCost(SetsYear) ","
CompLowCapCostPercent(SetsYear)","CompLowOMCost(SetsYear)","CompLowOMCostPercent(SetsYear)
","TCCompLow(SetsYear)","CompLowTCPercent(SetsYear) /
 ",Pipe," Pipe_CapCost ","
PipeCapCostPercent(SetsYear)","PipeOMCost(SetsYear)","PipeOMCostPercent(SetsYear)","TCPipe(SetsYea
r)","PipeTCPercent(SetsYear) /
 ",Purifier,"
PuriCapCost(SetsYear)","PuriCapCostPercent(SetsYear)","PuriOMCost(SetsYear)","PuriOMCostPercent(Set
sYear)","TCPuri(SetsYear)","PuriTCPercent(SetsYear) /
 ",Heavy_Compressor," CompTwoCapCost(SetsYear) ","
CompTwoCapCostPercent(SetsYear)","CompTwoOMCost(SetsYear)","CompTwoOMCostPercent(SetsYear
)","TCCompTwo(SetsYear)","CompTwoTCPercent(SetsYear) /
 ",Comp_Pipe," CompPipeCapCost ","
CompPipeCapCostPercent(SetsYear)","CompPipeOMCost(SetsYear)","CompPipeOMCostPercent(SetsYear)
","TCCompPipe(SetsYear)","CompPipeTCPercent(SetsYear) /
 ",Sum,"
TCapCost(SetsYear)","TCapCostPercent(SetsYear)","TOMCost(SetsYear)","TOMCostPercent(SetsYear)","T
otalCostCombine(SetsYear)",1,,"ActualNaturalGasPerYear",mmBTU,"LCOG(SetsYear)",$/mmBTU,"LCO
E(SetsYear)",$/mwh,"/
 /
 )
put /

*** Hubs
put "Table 2 - Hub Configurations"/
put ",,,,Purifier,,,,Heavy_Compressor"/
put
"TimeFrm,HubID,mmBTUperyear,CFH,Capacity,Number,Capital($),O&M($),Capacity,Number,Capital($),O
&M($)"/
loop((SetsYear),
 put Year(SetsYear)","/
 loop((Hubs),
 put ","Hubs.tl","AmountofGasmmBTU","AmountOfGas/

*loop purifier units
 loop((SetsPurifier)$SXPuri(SetsYear,SetsPurifier),
```

```
 put
",,,,"PPuriCapacity(SetsPurifier)","SXPuri(SetsYear,SetsPurifier)","PPuriCapCost(SetsPurifier)","PPuriOMCost(SetsPurifier) /
 );

*loop heavy compressors
 loop((SetsCompTwo)$SXCompTwo(SetsYear,SetsCompTwo),
 put
",,,,,,,"PCompTwoCapacity(SetsCompTwo)","SXCompTwo(SetsYear,SetsCompTwo)","PCompTwoCapCost(SetsCompTwo)","PCompTwoOMCost(SetsCompTwo)/
 );
);
put /

);

*** Individual farms
put "Table 3 - Farm Configurations"/
put ",,,,Cond_Water,,,,Low_Compressor"/
put
"TimeFrm,FarmID,mmBTUperyear,CFH,Capacity,Number,Capital($),O&M($),Capacity,Number,Capital($),O&M($)"/

loop((SetsYear),
 put Year(SetsYear)","/
 loop((Farms),
 put ","Farms.tl","PointGas(Farms)","PointGasCFH(Farms)/

*loop purifier units
 loop((SetsCondWater)$SXCondWater(SetsYear,Farms,SetsCondWater),
 put
",,,,"PCondWaterCapacity(SetsCondWater)","SXCondWater(SetsYear,Farms,SetsCondWater)","PCondWaterCapCost(SetsCondWater)","PCondWaterOMCost(SetsCondWater) /
 );

*loop heavy compressors
 loop((SetsCompLow)$SXCompLow(SetsYear,Farms,SetsCompLow),
 put
",,,,,,,"PCompLowCapacity(SetsCompLow)","SXCompLow(SetsYear,Farms,SetsCompLow)","PCompLowCapCost(SetsCompLow)","PCompLowOMCost(SetsCompLow)/
 );


 );
```

 put /

);

G.4. GAMS to GIS Pipeline Delineation Model VBA Scripts

GAMS to GIS Model

```
Private Sub CommandButton1_Click()
MsgBox "OK"
End Sub

Private Sub cmdCancel_Click()
Unload frmGAMStoGIS
End Sub

Private Sub cmdGAMS_Click()

Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter
Dim str As String
Filter = 1 'filter shapefile only

str = BrowseFolder("Open Output Folder")

If Len(str) = 0 Then Exit Sub
txtGAMS.Text = str
```

```
End Sub

Private Sub cmdOK_Click()

Dim strTemp As String
Dim PointBegin As String
Dim PointEnd As String
Dim PlantorSink As String
Dim Cap As Double
Dim Size As Double
Dim CostKm As Double
Dim SegCost As Double
Dim val As Variant
Dim iter As Long
Dim beginId As String
Dim endId As String
Dim normCost As String
Dim record, record1, record2 As String
Dim PointBeginId As String
Dim PointEndId As String

iter = 0

'Create the main route map empty
```

```
Call createMainRoute

strTemp = txtGAMS.Text & "\OutputPipe_s4.txt"
Dim count As Integer
count = 0

Open strTemp For Input As #1
Do While Not eof(1) ' Loop until end of file.
 Input #1, record
 count = count + 1
Loop
Close #1

Dim count2 As Integer
count2 = 0
Open strTemp For Input As #1
Do While Not eof(1) ' Loop until end of file.
 count2 = count2 + 1
 Input #1, record ' Read the line.
 val = Split(record)

 'Remove spaces from the split array
 Dim LastNonEmpty As Integer
 LastNonEmpty = -1
 For i = 0 To UBound(val)
 If val(i) <> "" Then
```

```
LastNonEmpty = LastNonEmpty + 1

val(LastNonEmpty) = val(i)

End If

Next

ReDim Preserve val(LastNonEmpty)



PointBegin = val(0)

PointEnd = val(1)

normCost = val(2)

Cap = val(3)

Size = val(4)

CostKm = val(5)

SegCost = val(6)

iter = iter + 1



Call createroute(PointBegin, PointEnd)



PointBeginId = VBA.Mid(PointBegin, 2)

PointEndId = VBA.Mid(PointEnd, 2)


'Please append this new route to the main route map

Call AppendPath(iter, CDbl(Cap), CDbl(Size), CDbl(CostKm), CDbl(SegCost), PointBeginId, PointEndId,
normCost)
```

```
Loop

Close #1 ' Close file.

MsgBox "Complete"

End Sub

Sub AppendPath(iter As Long, Cap As Double, Size As Double, CostKm As Double, SegCost As Double, beginId As String, endId As String, normCost As String)

Dim routeOutput As String

Dim tmpPathFC As String

Dim pp1 As Integer

Dim strScenario As String

pp1 = InStrRev(txtGAMS.Text, "\")

strScenario = VBA.Mid(txtGAMS.Text, pp1 + 1)

routeOutput = txtout.Text + "\" + txtRoute.Text

Call GetPath

strCWD = strPWD

workspace = strCWD + "\" + "ToolData"

scratchws = strCWD + "\" + "Scratch"
```

```
tmpPathFC = scratchws + "\" + "tmpPathFC.shp"

Dim GP As Object
Set GP = CreateObject("esriGeoprocessing.GpDispatch.1")
GP.OverwriteOutput = 1

GP.AddField_management tmpPathFC, "BeginID", "Text"
GP.CalculateField_management tmpPathFC, "BeginID", beginId
GP.AddField_management tmpPathFC, "EndID", "Text"
GP.CalculateField_management tmpPathFC, "EndID", endId
GP.AddField_management tmpPathFC, "NormCost", "Text"
GP.CalculateField_management tmpPathFC, "NormCost", normCost

GP.AddField_management tmpPathFC, "Id", "Long"
GP.CalculateField_management tmpPathFC, "Id", iter
GP.AddField_management tmpPathFC, "XCAP", "Double"
GP.CalculateField_management tmpPathFC, "XCAP", Cap
GP.AddField_management tmpPathFC, "XSIZE", "Double"
GP.CalculateField_management tmpPathFC, "XSIZE", Size
GP.AddField_management tmpPathFC, "XCOSTKM", "Double"
GP.CalculateField_management tmpPathFC, "XCOSTKM", CostKm
GP.AddField_management tmpPathFC, "SEGCOST", "Double"
GP.CalculateField_management tmpPathFC, "SEGCOST", SegCost
```

```
GP.DeleteField_management tmpPathFC, "ARCID;GRID_CODE;FROM_NODE;TO_NODE"

GP.Append_management tmpPathFC, routeOutput, Test

End Sub
Function createroute(PointBegin As String, PointEnd As String)

Dim PointBeginId As String
Dim PointEndId As String

 PointBeginId = VBA.Mid(PointBegin, 2)

 PointEndId = VBA.Mid(PointEnd, 2)

 Call createPlantToPlant(CStr(PointBeginId), CStr(PointEndId))

End Function

Public Sub createMainRoute()

Dim strCWD As String
Dim strMsg As String
Dim workspace As String
```

```
Dim scratchws As String
Dim routeOutput As String
Dim spatialreffile As String
Dim templateShape As String
Dim strScenario As String
Dim pp1 As Integer



pp1 = InStrRev(txtGAMS.Text, "\")
strScenario = VBA.Mid(txtGAMS.Text, pp1 + 1)

routeOutput = txtRoute.Text

Call GetPath
strCWD = strPWD
workspace = strCWD + "\" + "ToolData"
scratchws = strCWD + "\" + "Scratch"

spatialreffile = workspace + "\" + "USA Contiguous Albers Equal Area Conic.prj"

Dim pGeoDataset As IGeoDataset
Dim spatialRef As Object

Dim GP As Object
Set GP = CreateObject("esriGeoprocessing.GpDispatch.1")
```

```
GP.OverwriteOutput = 1

Dim pGPSettings As IGeoProcessorSettings
Dim pGPComHelper As IGPComHelper
Set pGPComHelper = GP
Set pGPSettings = pGPComHelper.EnvironmentManager
pGPSettings.AddOutputsToMap = False

Set spatialRef = GP.CreateObject("spatialreference")
spatialRef.CreateFromFile (spatialreffile)

GP.CreateFeatureClass_management txtout.Text, routeOutput, "POLYLINE", "", "", "", spatialRef

Dim shapefile As String

shapefile = txtout.Text + "\" + routeOutput

Call addRouteField(shapefile)

End Sub

Public Sub addRouteField(shapefile As String)
Dim pMxDoc As IMxDocument
Dim pFeatureLayer As IFeatureLayer
Dim pFeatureClass As IFeatureClass
Set pMxDoc = ThisDocument
```

```
AddShapeFile (shapefile)

Set pFeatureLayer = pMxDoc.FocusMap.Layer(0)
Set pFeatureClass = pFeatureLayer.FeatureClass

Call AddFieldIndividual(pFeatureClass, "BeginId", esriFieldTypeString)
Call AddFieldIndividual(pFeatureClass, "EndId", esriFieldTypeString)
Call AddFieldIndividual(pFeatureClass, "NormCost", esriFieldTypeString)
Call AddFieldIndividual(pFeatureClass, "XCAP", esriFieldTypeDouble, 32)
Call AddFieldIndividual(pFeatureClass, "XSIZE", esriFieldTypeDouble, 32)
Call AddFieldIndividual(pFeatureClass, "XCOSTKM", esriFieldTypeDouble, 32)
Call AddFieldIndividual(pFeatureClass, "SEGCOST", esriFieldTypeDouble, 32)

deleteLayer (0)

End Sub

Public Sub createPlantToPlant(plantBegin As String, plantEnd As String)

' search for the plantbegin in the plants layer
Dim costSurface As String
Dim costsurf As String

Dim CostDistance As String
Dim CostBackLink As String
```

```
Dim CostPath As String
Dim tmpsurf1 As String
Dim tmpsurf2 As String
Dim tmpPathFC As String
Dim point1 As String
Dim PointBeginId As String
Dim PointEndId As String
Dim strSQL1 As String
Dim strSQL2 As String
Dim pointbeginout As String
Dim pointendout As String
Dim strCostExtend As String


Call GetPath
strCWD = strPWD
workspace = strCWD + "\" + "ToolData"
scratchws = strCWD + "\" + "Scratch"
Dim strSurface As String

If ComboBox1.Text = "250" Then
strSurface = 250
ElseIf ComboBox1.Text = "1500" Then
strSurface = 1500
Else
strSurface = 2000
```

```
End If

strCostExtend = strCWD + "\" + "Data\CostSurfaces\costsurface" + strSurface + "m.img"

costSurface = strCWD + "\" + "Data\CostSurfaces\costsurface" + strSurface + "m.img"
costsurf = scratchws + "\CostSurf2"

CostDistance = scratchws + "\" + "costdistance"
CostBackLink = scratchws + "\" + "costbacklink"
CostPath = scratchws + "\" + "costpath"
tmpsurf1 = scratchws + "\" + "tmpsurf1"
tmpsurf2 = scratchws + "\" + "tmpsurf2"
tmpPathFC = scratchws + "\" + "tmpPathFC"

pointbeginout = scratchws + "\" + "pointbegin.shp"
pointendout = scratchws + "\" + "pointend.shp"


strSQL1 = "Facility_N=" & "'" & plantBegin & "'"
strSQL2 = "Facility_N=" & "'" & plantEnd & "'"

PointBegin = "plantbegin"
PointEnd = "plantend"

Dim GP As Object
Set GP = CreateObject("esriGeoprocessing.GpDispatch.1")
```

```
GP.OverwriteOutput = 1

GP.Extent = strCostExtend

GP.CopyRaster_management costSurface, costsurf

GP.MakeFeatureLayer_management txtPower.Text, PointBegin, strSQL1
GP.CopyFeatures_management PointBegin, pointbeginout

GP.MakeFeatureLayer_management txtPower.Text, PointEnd, strSQL2
GP.CopyFeatures_management PointEnd, pointendout

'create a cost distance from the pointbegin
GP.CostDistance_sa PointBegin, costsurf, CostDistance, "", CostBackLink

'create a costpath between the two points using costdistance
GP.CostPath_sa PointEnd, CostDistance, CostBackLink, CostPath

'convert costbacklink to a flow direction raster
GP.Minus_sa CostBackLink, 1, tmpsurf1
GP.Power_sa 2, tmpsurf1, tmpsurf2
GP.Delete_management tmpsurf1
GP.Int_sa tmpsurf2, tmpsurf1

'convert the cost path to a polyline
GP.StreamToFeature_sa CostPath, tmpsurf1, tmpPathFC, Simplify
```

```
GP.Delete_management tmpsurf1



End Sub

Public Sub createPlantToSink(plantBegin As String, plantEnd As String)

Dim costSurface As String
Dim CostDistance As String
Dim CostBackLink As String
Dim CostPath As String
Dim tmpsurf1 As String
Dim tmpsurf2 As String
Dim tmpPathFC As String
Dim point1 As String
Dim PointBeginId As String
Dim PointEndId As String
Dim strSQL1 As String
Dim strSQL2 As String
Dim pointbeginout As String
Dim pointendout As String

Call GetPath
strCWD = strPWD
workspace = strCWD + "\" + "ToolData"
scratchws = strCWD + "\" + "Scratch"
```

```
costSurface = strCWD + "\" + "Data\CostSurfaces\costsurf_nc21_nad83_250m.img"
CostDistance = scratchws + "\" + "costdistance"
CostBackLink = scratchws + "\" + "costbacklink"
CostPath = scratchws + "\" + "costpath"
tmpsurf1 = scratchws + "\" + "tmpsurf1"
tmpsurf2 = scratchws + "\" + "tmpsurf2"
tmpPathFC = scratchws + "\" + "tmpPathFC"

pointbeginout = scratchws + "\" + "pointbegin.shp"
pointendout = scratchws + "\" + "pointend.shp"

PointBeginId = "plantBegin"
PointEndId = "plantEnd"

strSQL1 = "PLANT_GRP=" & PointBeginId
strSQL2 = "SiteId=" & PointEndId
'MsgBox "point Begin is: " + Cstr(PointBegin)

PointBegin = "pointbegin"
PointEnd = "pointend"

Dim GP As Object
Set GP = CreateObject("esriGeoprocessing.GpDispatch.1")
GP.OverwriteOutput = 1
```

```
GP.MakeFeatureLayer_management txtPower.Text, PointBegin, strSQL1

GP.CopyFeatures_management PointBegin, pointbeginout


GP.MakeFeatureLayer_management TxtSink.Text, PointEnd, strSQL2

GP.CopyFeatures_management PointEnd, pointendout


'create a cost distance from the pointbegin

GP.CostDistance_sa pointbeginout, costSurface, CostDistance, "#", CostBackLink


'create a costpath between the two points using costdistance

GP.CostPath_sa pointendout, CostDistance, CostBackLink, CostPath


'convert costbacklink to a flow direction raster

GP.Minus_sa CostBackLink, 1, tmpsurf1

GP.Power_sa 2, tmpsurf1, tmpsurf2

GP.Delete_management tmpsurf1

GP.Int_sa tmpsurf2, tmpsurf1


'convert the cost path to a polyline

GP.StreamToFeature_sa CostPath, tmpsurf1, tmpPathFC, Simplify

GP.Delete_management tmpsurf1

' search for the plantbegin the plants layer

' search for the plantend in the sinks layer



End Sub
```

```
Private Sub cmdoutput_Click()

Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter

Dim str As String

Filter = 1 'filter shapefile only


str = BrowseFolder("Open Output Folder")


If Len(str) = 0 Then Exit Sub

txtout.Text = str

End Sub


Private Sub cmdsink_Click()

Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter

Dim str As String

Dim num As Integer


Dim strList() As String


Filter = 1 'filter shapefile only


Call OpenDialog(str, Filter)




If Len(str) = 0 Then Exit Sub

TxtSink.Text = str
```

```
End Sub

Private Sub cmdSource_Click()
Dim Filter As Byte 'Filter type: k = 1=> Shapefile filter; 2=>pGeoFilter;3=>pFeaFilter
Dim str As String
Dim num As Integer

Dim strList() As String

Filter = 1 'filter shapefile only

Call OpenDialog(str, Filter)


If Len(str) = 0 Then Exit Sub
txtPower.Text = str

End Sub

Private Sub Frame2_Click()

End Sub

Private Sub FrameSource_Click()

End Sub
```

```
Private Sub ListBox1_Click()

End Sub

Private Sub label_progress_Click()

End Sub

Private Sub txtGAMS_Change()

Dim pp1 As Integer
Dim strScenario As String
Dim routeOutput As String

pp1 = InStrRev(txtGAMS.Text, "\")
strScenario = VBA.Mid(txtGAMS.Text, pp1 + 1)

routeOutput = "Route_" + strScenario
txtRoute.Text = routeOutput

End Sub

Private Sub txtout_Change()

End Sub
```

```
Private Sub txtPower_Change()


End Sub

Private Sub txtRoute_Change()

End Sub

Private Sub UserForm_Initialize()
txtGAMS.Text = "G:\BIOGAS\MathematicalModeling\DATA\Scenario3\s3_grp1c\"
txtPower.Text = "G:\BIOGAS\gis_data\subgrouping\scenario3\s3_grp1c.shp"
txtout.Text = "G:\BIOGAS\MathematicalModeling\DATA\Scenario3\s3_grp1c\map\"
txtRoute.Text = "Route_Output.shp"
ComboBox1.AddItem "250"
ComboBox1.AddItem "1500"
ComboBox1.AddItem "2000"

ComboBox1.Text = "250"

End Sub
```

The Nicholas Institute for Environmental Policy Solutions

The Nicholas Institute for Environmental Policy Solutions at Duke University is a nonpartisan institute founded in 2005 to help decision makers in government, the private sector, and the nonprofit community address critical environmental challenges. The Nichols Institute responds to the demand for high-quality and timely data and acts as an "honest broker" in policy debates by convening and fostering open, ongoing dialogue between stakeholders on all sides of the issues and providing policy-relevant analysis based on academic research. The Nicholas Institute's leadership and staff leverage the broad expertise of Duke University as well as public and private partners worldwide. Since its inception, the Nicholas Institute has earned a distinguished reputation for its innovative approach to developing multilateral, nonpartisan, and economically viable solutions to pressing environmental challenges.

for more information please contact:

Nicholas Institute for Environmental Policy Solutions
Duke University
Box 90335
Durham, North Carolina 27708
919.613.8709
919.613.8712 fax
nicholasinstitute@duke.edu
www.nicholasinstitute.duke.edu