Exhibit No. 213

OPC – Exhibit 213
Lena Mantle
Rebuttal Testimony
File No. GR-2021-0108

Exhibit No.:	________________
Issue(s):	Miscellaneous Tariff Issues/ RNG Proposals/Carbon Neutral Initiative/WNAR
Witness/Type of Exhibit:	Mantle/Rebuttal
Sponsoring Party:	Public Counsel
Case No.:	GR-2021-0108

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

SPIRE MISSOURI, INC.

CASE NO. GR-2021-0108

** **

Denotes Confidential Information that has been Redacted

June 17, 2021

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	)))))	Case No. GR-2021-0108

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Lena M. Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena M. Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M Mantle

Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 17th day of June 2021.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

Tiffany Hildebrand

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

LENA M. MANTLE

SPIRE MISSOURI, INC.

d/b/a SPIRE MISSOURI EAST & SPIRE MISSOURI WEST

CASE NO. GR-2021-0108

<u>Introduction</u>

Q. Please state your name and business address.

A. My name is Lena M. Mantle. My business address is P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Lena M. Mantle that filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. In this rebuttal testimony I provide responses to:

1. Two of Spire's miscellaneous tariff changes:
    a. R-15.2 Free Extensions; and
    b. R-25 Usage Estimating Procedure;
2. Spire's request for a voluntary renewable natural gas program offering as proposed in the direct testimony of Spire witness Wesley E. Selinger;
3. Spire's request to include up to 5% renewable natural gas in its gas supply as proposed in the direct testimony of Spire witness Wesley E. Selinger;
4. Spire's request for Commission approval of a carbon neutral initiative offering as proposed in the direct testimony of Spire witness Scott A. Weitzel;
5. Spire's rate normalization adjustment ("RNA") rider proposed in the direct testimony of Spire witness Wesley E. Selinger; and
6. Staff's proposed RNA rider proposed in the Staff Class Cost-of-Service Report.

Q. Would you summarize the recommendations you make in this rebuttal testimony?

A. I make the following recommendations in this testimony:

- The Commission not approve Spire's proposed tariff language allowing no cost line extensions at Spire's discretion;
- The Commission require Spire to document in its tariff its current estimation practices for customers without a meter reading. When it develops and settles on a better methodology and before it implements a change, Spire should file a revised tariff sheet for approval by the Commission documenting the new methodology;
- The Commission wait until rules regarding voluntary renewable natural gas programs are effective before approving such a program for Spire;
- The Commission not allow Spire to procure any of its gas supply from renewable sources unless the total cost of the renewable gas is comparable to the non-renewable natural gas Spire is purchasing for its customers;
- The Commission not approve the Voluntary Carbon Neutral Initiative Offering ("Carbon Neutral Initiative") proposed by Spire;
- The Commission not approve any type of mechanism to account for fluctuations in weather and/or conservation because Spire did not provide testimony justifying why the Commission should approve a mechanism; and
- If the Commission believes Spire has provided information that details its need for a mechanism accounting for weather and some conservation, it should approve the WNAR I recommended in my direct testimony.

Miscellaneous Tariff Issues

Q. Which of Spire's proposed tariff sheet changes are you addressing in this testimony?

A. I am addressing Spire's proposed changes to its Extension of Distribution Facilities rules and regulations found on proposed sheets R-15 through R-15.3. In particular, I address Spire's addition of a provision in the Free Extension section on proposed tariff sheet R-15.2 that would allow it, at its discretion, to install service at no cost to prospective customers.

I will also address Spire's proposed tariff sheet R-25 which removes a description of how estimated usage is calculated and replaces it with vague language that gives little information on how Spire will be estimating bills for customers without a meter reading.

Q. Did Spire file testimony explaining its rational for these changes?

A. No. These are only two of many changes that Spire did not file testimony providing rationales for.

Q. Did Spire note in its minimum filing requirement that its proposed tariff sheets included changes to these tariff sheets?

A. No. These are only two of many changes Spire did not point out in its minimum filing requirements.

Q. Do you support the other changes to Spire's proposed tariff sheets that were filed but not detailed in Spire's filings?

A. I do not have enough information to either support or not support any changes other than the two in this testimony.

Q. Regarding the cost to install service at no cost, what addition is Spire proposing?

A. Spire is proposing the following addition to its tariff sheet R-15.2 in the *Free Extension* section of its *Extension of Distribution Facilities* regulations:

> For any prospective customer, at the Company's discretion, the amount of main and service the Company will install at no cost to the customer may be determined by the Company from an analysis of the character of service requested, the estimated annual revenue to be derived from the customer, the estimated annual cost of providing gas service and the estimated annual return to be derived from such investment.

Q. Why should this not be included in Spire's tariff?

A. While this provision does require Spire to consider certain aspects of the prospective customer (e.g. analysis of character of service requested, estimated annual revenue, estimated annual cost, and estimated annual return), it does not describe the parameters that need to be met to receive service at no costs. For example, it does not say that this applies to industrial customers that will employ more than 100 people or a customer who will provide annual revenue to Spire ten percent higher than it will cost Spire, or that they estimate there will be a positive return derived from such investment. The provision just says that Spire will look at these things and make a determination whether it will provide extensions at no cost to the customer.

This provision allows Spire to act discriminatorily and in a manner that is likely to increase costs to its customers. Therefore, the Commission should not allow this provision in Spire's tariff sheets.

Q. Regarding the estimation of customer bills, what is Spire proposing?

A. Spire is proposing the following language on tariff sheet R-25:

30. Usage Estimating Procedure:

> Whenever it is necessary to estimate a particular customer's monthly consumption, such consumption shall be estimated based on historical usage data for the customer location, if available. Where historical usage data at the customer location is not available, the customer's estimate will be based on average usage data for similarly situated customers.

Q. How is it different from what is currently on Spire's tariff sheet R-25?

A. The current tariff reads:

> Whenever it is necessary to estimate a particular customer's monthly consumption, such consumption shall be estimated by determining the actual usage at the customer's location in a prior comparable period and then adjusting such usage to reflect weather differences. Where actual usage data at the customer's location is not available for a comparable period, the estimation will be performed by determining actual usage at the customer's location in the previous billing period, and then adjusting such usage to reflect weather differences. Where actual usage data at the customer's location is not available for the previous billing period, the estimation will be performed by determining the relationship of actual usage at the customer's location to the average usage of comparable customers as determined by the Company in a prior period, and applying that relationship to the average usage of comparable customers in the estimation period. Specifically, usage for a customer's billing period for this last alternative will be based on the following formula:
>
> (A / B) x C x No. of days in current billing period; Where:
>
> A= customer's actual use per day in a prior billing period;
>
> B= the average use per customer per day for comparable customers using ending meter reading dates closest to that of the prior billing period for the account being estimated;
>
> C= the average use per customer per day for comparable customers using ending meter reading dates closest to that of the current billing period for the account being estimated
>
> Where actual usage data at the customer's location is not available, the customer's use will be based on average usage for comparable customers.

The current tariff sheet not only explains what data will be used to estimate usage for billing but also explains how the usage will be estimated.

Q. Did Spire provide any testimony supporting this change?

A. No. However, in response to Staff data request 144, Spire did provide the following explanation for the change.

> The elimination of the estimation formula was recommended in order to provide flexibility in manual and system estimations, as well as to be able to use technology enhancements to continually increase the accuracy of estimations. This will ultimately increase customer satisfaction and reduce complaints. In addition, Spire has begun to experiment with machine learning in calculating usage estimates, and the early trials on this are showing high accuracy when we compared to actual usage. Technology enhancements, like machine learning will enable us to estimate with a high level of accuracy as opposed to having a specific formula in the tariff.

It seems that Spire intentionally made the tariff language vague because it is looking at other methodologies at this time and wants to be able to use whatever methodology it later develops to estimate a customer's usage. As a result, the customer and the Commission will not have any idea of how a Spire bill is estimated.

Q. Does Spire's proposed change meet the Commission's requirement in 20 CSR 4240-13.020(2)(C)1 that Spire have an estimating procedure that it has filed with the Commission?

A. No. The proposed tariff language does not describe the procedure Spire will apply to determine the estimated usage. It only provides what information will be employed in estimating usage.

Q. Is this a tariff provision that can only be updated in a rate case?

A. No. It can and should be updated between rate cases as new, more accurate methodologies for estimating usage are developed.

Q. What is your recommendation concerning the tariff sheet's description regarding customer usage estimation?

A. I recommend the Commission require Spire to document its current practices in its tariff. When it develops and settles on a better methodology and before it implements a change, Spire should file a revised tariff sheet for approval by the Commission accurately documenting the new methodology. This will give Spire's customers and the Commission an understanding of the estimating procedure that Spire is employing.

<u>Renewable Natural Gas Recommendations</u>

Q. What is renewable natural gas?

A. The Environmental Protection Agency ("EPA") provides the following definition of renewable natural gas ("RNG") in its report *An Overview of Renewable Natural Gas from Biogas* published in January 2021.[1]

> RNG is a term used to describe anaerobically-generated biogas that has been upgraded (or refined) for use in place of fossil natural gas.

Q. What is Spire proposing with respect to renewable natural gas?

A. Spire witness Selinger includes his direct testimony two proposals related to RNG.[2] One is a voluntary program where customers pay more with the expectation that the funds will be used to purchase RNG. The other proposal is that the Commission allow Spire to procure up to 5% of its gas supply from renewable sources and pass the additional costs to the customers through its purchased gas adjustment ("PGA").

Q. What is your recommendation regarding the voluntary RNG program?

A. I recommend the Commission not approve the voluntary RNG program proposed by Spire. The Missouri Legislature passed HB 734 in the 2021 legislative session and is currently waiting for the Governor's signature to become law. It includes §

[1] This report is attached to this testimony as Schedule LMM-R-4.
[2] Pages 39-41.

386.895, which requires the Commission to adopt rules for gas corporations to offer a voluntary renewable gas program. The Commission has not yet adopted such rules so the approval of such a program would be premature. The appropriate time for Spire to request Commission approval of such a program is after such a rule is effective, not before the rule is written.

Q. Did Spire provide an exemplar tariff sheet describing this program and setting out the costs and parameters of the program?

A. I could not find any such tariff sheets in Spire's minimum filing requirements.

Q. What is your recommendation regarding Spire's request to procure up to 5% of its gas supply from renewable sources?

A. I recommend the Commission not allow Spire to procure any of its gas supply from renewable sources unless the total cost of the renewable gas is comparable to the non-renewable natural gas Spire is purchasing for its customers.

Q. Why?

A. The amount of RNG currently being produced is limited and the amount that could be produced is limited. As states across the nation are considering mandates for RNG much like they have for electricity generated with renewables, the limited supply and the increased demand will drive the prices higher. While allowing Spire to purchase some RNG may encourage more development, it is not the Commission's role to encourage RNG by requiring, or even "allowing" as Spire is requesting, the purchase of RNG with all of the increased cost flowing through to the customer. The Commission is to require the economic provision of natural gas to customers at the lowest cost while assuring safety. If Spire desires to commit to the purchase of RNG, the Company should shoulder the cost for RNG that is above the annual weighted cost of gas without RNG.

Q. Did Spire provide an estimate of the cost of RNG?

A. No, it did not provide any information on the cost or availability of RNG in Missouri in its direct testimony.

Q. Did you have an estimate of the costs of RNG?

A. I found an EPA study published in fall of 2016 that determined a cost range of \$7/mmbtu (very large-scale) to \$25/mmbtu (small-scale) for projects upgrading biogas to RNG for pipeline injection.[3] It is likely these costs have increased due to increases in state mandates for gas utilities to purchase RNG. Currently the market price of gas is around \$3/mmbtu.

Allowing Spire to procure up to 5% of its gas supply with no information on the cost and availability of RNG could have a significant impact on customer's bills despite Spire's assertion that the impact would be negligible.[4]

Q. Are there other things the Commission should take into consideration before allowing Spire to purchase RNG as a part of its gas supply to meet its customers' needs?

A. Yes. If the Commission allowed Spire to purchase RNG and pass the costs through the purchased gas adjustment ("PGA"), then Spire has no skin in the game. Spire can purchase whatever amount it can find up to 5% at whatever cost it incurs and the cost would flow through the PGA to customers. All the risk of availability and cost is then on customers. Any and all purchases of RNG up to 5% of Spire's total gas supply could not be shown to be imprudent regardless of the cost if the Commission approves the language Spire is proposing in its PGA tariff sheet.

Finally, by allowing Spire to purchase RNG as a part of its supply, the increased costs of RNG would be passed on to customers regardless of whether or

---

[3] U.S. EPA. September 2016. Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies. EPA/600/R-16/099. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100QCXZ.PDF?Dockey=P100QCXZ.PDF .

[4] Direct testimony of Spire witness Wesley E. Selinger, page 40.

not the customer can afford an increase in their bills. Spire has many customers to which even a small increase in cost results in a hardship. Instead of allowing Spire to act in a manner that knowingly will increase the natural gas cost and pass that cost directly to all customers, the Commission should move forward creating rules that set the parameters for Spire to offer a program in the future that allows customers who desire to pay for RNG to do so voluntarily.

<u>**Voluntary Carbon Neutral Initiative Offering**</u>

Q. Would you summarize your understanding of the Voluntary Carbon Neutral Initiative Offering?[5]

A. For $4 a month, a customer can, with Spire acting as a conduit, team up with Forest Re-Leaf of Missouri ("ReLeaf") who will plant a tree to offset the customer's approximate annual natural gas carbon footprint over the life of the tree. The $4 a month includes the price of the trees and planting the trees, with 20% of the monthly costs covering administration and marketing costs. The monthly fee could change, at Spire's discretion, increasing to as much as $10 a month in 2024 and what the payment is funding could change to investing in a variety of other projects.[6]

Q. What is your recommendation regarding this offering?

A. I recommend the Commission not approve the Voluntary Carbon Neutral Initiative Offering ("Carbon Neutral Initiative") proposed by Spire.

Q. Why?

A. While I applaud ReLeaf's efforts, there is no need for customers to pay Spire as a middleman using the customers' money for Spire's administration and marketing. Much the same could be achieved simply by Spire putting a link on its website to direct interested customers to ReLeaf removing the need for Spire to act as a

[5] Direct testimony of Spire witness Scott A. Weitzel, pages 27-29.
[6] Direct testimony of Scott A. Weitzel, Schedule SAW-1, page 2 of 7.

middleman. ReLeaf would be in charge of collecting and receiving all the funds. This would eliminate the quandary of what partial bill payments apply. In addition, the 20% the customer would be paying Spire for administration and marketing, would go to ReLeaf expanding and planting more trees. If Spire wants to contribute to funding and marketing of ReLeaf, it may do so from its earnings, not its customers.

Q. Is there any other reason the Commission should not approve Spire's Carbon Neutral Initiative?

A. Yes. The Carbon Neutral Initiative proposed by Spire is fluid. The starting cost is $4 a month. It might increase to $6 and then at some point $10. The timing and amounts are to be determined by Spire in the future. The funds collected from customers remaining after Spire keeps 20% for administrative and marketing costs will be used to plant trees, or maybe invest in financial carbon offsets, technologies to sequester or eliminate carbon output, land restoration or even technologies not yet identified. Changes can be made at the will and discretion of Spire.

Q. What would be the Commission oversight of this program?

A. None other than approving the offering in this rate case. Spire commits to filing costs and program details and to submit an annual report but Spire did not provide exemplar tariff sheets that outline initial objectives and costs of the Carbon Neutral Incentive for Commission approval for this program.

Q. Would you summarize your position regarding Spire's Carbon Neutral Initiative?

A. The Commission should not approve Spire's Carbon Neutral Initiative. As proposed by Spire, program objectives and costs can change at the will of Spire with no approval of the Commission.

Q. Are you opposed to the initiative itself?

A. No. What I am opposed to is Spire acting as an unnecessary middleman for this program while absorbing 20% of the contributions made by its customers. I have no problem with individual customers choosing to donate money to help plant trees, but if Spire wishes to support the program directly then it should do so with shareholder money. This is especially true if Spire intends to promote itself or support its public image using this proposed Carbon Neutral Initiative. It would be immensely insincere for a utility to promote itself as charitable "good actor" based on the donations of others while the utility itself spends not a dime.

<u>**Mechanism to Account for Weather and Conservation**</u>

Q. What is the enabling statute for a mechanism to account for fluctuations in revenue due to weather and conservation?

A. I have been advised by my legal counsel that it is § 386.266.3. This section states in part:

> Subject to the requirements of this section, any gas or electric corporation may make an application to the commission to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both.

Q. Should the Commission approve any type of mechanism for Spire under this statute in this rate case?

A. No. As I stated in my direct testimony, I recommend the Commission not approve any type of mechanism to account for fluctuations in weather and/or conservation because Spire did not provide testimony justifying why the Commission should approve a mechanism allowed by this statute for Spire. Instead, Spire presumed that since the Commission approved a mechanism under this statute in the last case, it was entitled to such a mechanism. Section 386.266.5 provides that the

Commission has "the power to approve, modify, or reject" an adjustment mechanism to account for the impact of weather, conservation, or both. This indicates that such a mechanism is a privilege, not a right and should be justified to the Commission in each general rate case for approval, continuation, or modification. If a utility cannot take the time and effort to provide testimony detailing to the Commission why a mechanism that shifts risk from the utility to its customers should be approved, then it should not be allowed such a mechanism. This is a customer protection that should not be short-changed.

Q. If this is your recommendation to the Commission, what is the purpose of your rebuttal testimony with respect to a rate adjustment mechanism for the impact of weather, conservation, or both?

A. I assume that, after reading my direct testimony, Spire will provide in its rebuttal a rationale for why the Commission should approve a mechanism. This testimony explains why the Commission should not approve the mechanism proposed by Spire even with Staff's proposed modifications. Even so, the recommendation in my direct testimony that the Commission should not grant Spire a weather/conservation mechanism because Spire treated it as a right and not as a privilege still stands.

<u>Weather Normalization Adjustment Rider vs. Rate Normalization Adjustment</u>

Q. What parties in this case are proposing mechanisms that adjust revenues for weather, conservation, or both?

A. OPC is the only party that has proposed a mechanism that accounts for weather and some conservation impacts on revenues.

Q. Didn't Spire and Staff also recommend the Commission approve a mechanism to adjust for weather, conservation, or both?

A. No. They both proposed a rate normalization mechanism ("RNA") that insulates Spire from fluctuations in the Block 2 portions of the revenue requirement of Spire's residential and small commercial customer classes.[7] This mechanism removes from Spire all risk of it recovering this portion of its revenue requirement that are subject to volumetric recovery for these two classes.

Q. Would the mechanism proposed by Spire account for changes revenue due to weather and conservation?

A. It accounts for ***all*** changes in revenue in this second block, regardless of the reason for the change including changes in revenues due to weather and conservation. Much like the rate stabilization mechanism proposed by Spire in the last case that the Commission found inconsistent with the statutory requirements,[8] the RNA would account for fuel switching, rate class switching, and economic factors that impact usage in the second block and not just changes due to weather and conservation.

Q. Are there any other reasons the actual revenues would fluctuate from rate case revenues?

A. An additional reason may be that the normalization and annualization of the billing determinants and revenues in this case is not an accurate representation of future usage and revenues.

---

[7] Staff CCOS report, page 39.
[8] GR-2017-0215 and GR-2017-0216, *Report and Order*, page 83.

Q. Do you have any reason to believe that the normalizations and annualizations adjustments to class billing determinants and revenues in this case are not accurate?

A. No. However, the adjustments in this case are estimates that do not, and should not, account for changes in usage for things like pandemics, recessions, inflation, or wars. If the Commission approves the RNA requested by Spire and Staff, Spire is assured a constant level of revenues regardless of what happened to the economy and the world during the test year and after this rate case regardless of the impact of these uncertainties on its customers.

Q. How is the weather normalization adjustment rider ("WNAR") that you proposed different?

A. The WNAR that I have recommended is consistent with Spire's current WNAR that the Commission found was in the public interest in Case No. GR-2017-0215. With a WNAR, adjustments to revenue are based on the relationship between usage and weather at the time of the rate case and the difference between actual and normal weather. It does account for some conservation but also leaves some risk associated with revenue changes due to conservation on Spire as I described in my direct testimony. It adjusts revenue only for weather and a portion of the conservation as allowed by statute.

Q. Does the rate normalization adjustment mechanism ("RNA") account for both weather and conservation?

A. The RNA mechanism assures Spire that it will recover a predetermined revenue, which would include revenue changes due to weather and conservation along with changes that occurred for other reasons.

Q. Could there be any unintended consequences if the Commission approved a RNA?

A. Yes. The normalized baseline revenue for this mechanism is based on the residential and small general service revenue requirements as determined in this case. Utilities typically are neutral regarding class cost-of-service allocation of revenue requirement to the classes as long as the sum of the revenue requirements of the classes equals the revenue requirement set by the Commission. If the Commission approves a RNA mechanism, Spire may become very interested in what revenues are allocated to what customer classes. The greater the revenue requirement that is placed on its small customers, the lower Spire's risk of recovering the revenue requirement set in this case since it will be guaranteed a portion of the revenue requirement allocated to the residential and small commercial customer classes.

Q. What are the implications of the Commission approving a WNAR to other aspects of the rate case process?

A. If the Commission approves a WNAR, the parties will work to provide an accurate measure of weather and accurately define the relationship of the customer classes to weather.

Q. Would that not be important with a RNA mechanism?

A. While the weather normalization of revenues would still be important, the critical objective of a RNA is revenues, not correctly measuring the relationship between weather and usage.

Q. Before getting into specifics of the testimonies of Spire and Staff regarding the RNA, do you have concerns with the concept of the RNA mechanism proposed by Spire and Staff?

A. Yes. As I have already explained, the RNA is essentially decoupling the revenues received from the residential and small general service customers from their usage thus removing almost all of the revenue risk from Spire and placing that risk on customers. In addition, I have the following concerns:

1. The RNA which is recovered/returned to all customers based on usage, yet it is calculated from only the amount of usage in the 2nd block; and
2. Spire would continue to recover revenue for small general service ("SGS") customers that move to the large general service ("LGS") class resulting in double-recovery for the usage from these rate switchers.

Q. Why is it a concern that all usage is charged/credited the RNA?

A. The RNA rider amount is based on the change in usage in a second block and assumes weather and conservation only impacts the usage of the second block. However, after the RNA rate is calculated, it is applied to all usage, regardless of what block the usage falls in. This results in customers with low usage, i.e. non-weather sensitive customers with little room for conservation, being charged more because other customers were more weather-sensitive or conserved energy.

Q. Could there be a modification to the RNA to account for this?

A. Yes. The RNA rate could be modified to only be charged to the second block usage.

Q. How would Spire receive revenue twice for a SGS customer that move to the LGS class?

A. There are always some large SGS customers that are on the edge of being LGS customers. The usage of these customers are included in the normalized rate case block usage in the rate case. If one of these customers move to the LGS class, then Spire would receive the revenues from what the customer pays in the LGS class and the other SGS customers would make up the revenues now missing from the SGS class. Thus, Spire would be getting revenues twice for this customer.

Q. Could there be a modification to the RNA to account for this?

A. Yes. The normalized Rate Case Block Usage used in the calculation of the RNA rate could be adjusted for the removal of the annual usage of any customer that has switched to the LGS class each year.

<u>**Rebuttal of Spire Witness Wesley E. Selinger Regarding the RNA**</u>

Q. Does Spire currently have a WNAR or a RNA?

A. Currently Spire has a Commission-approved WNAR. In this case, Spire is asking its WNAR to be discontinued and replaced with a RNA.

Q. Is the RNA Spire is proposing a modification of its current WNAR?

A. No. It is a completely different mechanism.

Q. Would you summarize your understanding of why Spire did not ask for a continuation or modification of its WNAR?

A. Spire provides very little testimony regarding why it is dissatisfied with the WNAR and is instead asking for a RNA. In his direct testimony, Spire witness Selinger basically states two reasons why Spire does not want to continue with the WNAR:

1. Issues and anomalies; and
2. The WNAR does not directly address conservation.

Q. Does the current WNAR or the modified WNAR you propose in your direct testimony directly address conservation?

A. No. However, as I explained in my direct testimony, it does reflect some conservation.

Q. Does the RNA proposed by Spire directly address conservation?

A. No. It does not directly address either conservation or weather. It only addresses the difference between rate case revenue requirement and the revenue actually collected.

Q. In your reading of § 386.266, is it essential that the WNAR address revenue effects caused by conservation?

A. While I am not an attorney, my reading of § 386.266.6 is that it allows the Commission to approve a mechanism that reflects changes in revenues due to variations in *either* weather, conservation, or both. It is not essential that the WNAR reflect the effect on revenue of conservation. The way I read the statute, the Commission can approve a mechanism that reflects the impact on revenue of just weather, just conservation, or both.

Q. Did Mr. Selinger describe the "issues" that Spire has with the WNAR in his testimony?

A. No. He merely mentioned that Spire had issues with the WNAR. To find out what these issues were, I requested a detailed description of these issues in OPC data request 8000.

Q. What was Spire's response?

A. Spire responded[9] that one issue was that the WNAR was more complicated than it needed to be. According to Spire, the "complications" included having to update

---

[9] Spire's response with its description of the issues is attached as Schedule LMM-R-1 to this testimony.

the WNAR semi-annually and the fact that there are four separate rate components. Spire also sees that having to calculate the weather adjustments by billing cycle, the use of ranked degree days, and requiring an unbilled calculation as making this mechanism complicated. Finally, according to Spire the mechanism did not provide as close a correlation to volumetric variances as it wanted the mechanism to do.

Q. First of all, is a simple mechanism better than a complex mechanism?

A. Typically, simple is better than complex. However, if the objective is to account for fluctuations in revenue due to weather as stated in § 386.266.3, then complex is more accurate and therefore better than simple.

Even so, changes can be made to Spire's current WNAR that would make it simpler such as annual filings instead of semi-annual filings and annual recovery periods. In my direct testimony, I proposed modifications to Spire's WNAR that make it simpler and easier to understand.

In addition, I proposed, in my Class Cost-of-Service direct testimony, a different way to present the rate calculation that, along with annual filings, eliminates the need for four different rate components.

Q. Can the billing cycle analysis and ranked degree days that Spire said complicates the WNAR be simplified?

A. No. Billing cycle analysis and using ranked degree days cannot be simplified without sacrificing accuracy. Billing cycle analysis is necessary to match the correct weather to the usage. Ranking degree days to assign normal weather results in as little weather adjustment for each billing cycle as possible.

Q. Would you provide further explanation of why billing cycle analysis is necessary?

A. Schedule LMM-R-2 shows a graphical representation of the difference between a billing month and a calendar month. Spire has 18 billing cycles. The dates the meters are read are different for each billing cycle.

Spire East's actual read dates for the billing month of December 2019 are shown in Schedule LMM-R-2. Billing cycle 1 is read on December 1. The December billing month usage for billing cycle 1 is the sum of usage from October 31 through November 30. It is considered the December billing month because it is read on December 1 even though *none* of the usage in the billing cycle actually occurred in the December calendar month. Weather that occurred from October 31 through November 30 impacted the usage for the December billing month for billing cycle 1. It was colder than normal during this time period with an actual heating degree days ("HDD") of 729 with the normal HDD for that same time period being 574[10] signifying that, over this December billing cycle, the weather was colder than normal.

The last billing cycle is read on December 29. The December billing month usage for billing cycle 18 is the sum of the usage from November 27 through December 29. The usage in this billing cycle was impacted by weather that occurred from November 27 through December 28. It was warmer than normal for billing cycle 18 with actual HDD of 823 and normal HDD of 902.

To properly account for the weather that influenced billing cycle 1 and 18, actual and normal weather from two different time series must be matched to the usage. The actual weather for the December calendar month of 783 HDD and normal of 900 HDD would not explain the usage in billing cycle 1 since all of the natural gas in that billing cycle was used prior to the December calendar month.

[10] Actual and normal HDD are shown at the right of the table for each billing cycle as the sum of the daily actual and normal degree days shown at the bottom of the table.

Using the December calendar month weather cannot even explain the usage in billing cycle 18 since it includes five days of November weather and does not include three days of the December calendar month weather.

The actual and normal HDD for each billing cycle is shown numerically and graphically on Schedule LMM-R-2, along with the December calendar month actual and normal HDD. I have provided the actual and normal HDD for billing cycles 1 and 18, and the December calendar months below.

	Heating Degree Days ("HDD")		
	Actual	Normal	Difference
Billing Cycle 1	729	574	-155
Billing Cycle 18	823	902	79
December Calendar	783	900	117

The negative difference for billing cycle 1 represents that for the time period of this billing cycle, which was mostly November, the weather was colder than normal. The positive difference for the December calendar month indicates that, for the time period of December 1, 2019, through December 31, 2019, the weather was warmer than normal. This shows that the weather in the December calendar month is not representative of the weather for billing cycle 1 or any of the other billing cycles. Therefore, to accurately reflect the relationship between usage and weather, the analysis must be done on a billing cycle basis. A simple method of comparing billing month usage to calendar weather would be grossly inaccurate.

Q. Is this matching of weather to billing cycle complicated?

A. It should not be. Computer programs can be written that quickly do the matching of actual and normal heating degree days to each billing cycle. This should have already been done with Spire's current WNAR.

Q. What is Spire referring to when it uses the term "ranked degree days?"

A. Spire is referring to the Staff's methodology that calculates 365 normal degree days values and assigns the values to the days of the year. I have attached as Schedule LMM-R-3, the direct testimony in Case GO-2019-0058 of Staff witness Dr. Seoung Joun Won describing how normal degreed days are calculated and the importance of the assignment of the 365 normal degree days to the correct day. The Commission found in Case GO-2019-0058:

> Staff's ranking method reduces the daily variations between actual and normal gas usage when it aligns billing cycles within the billing month with those in the rate case. Reducing the daily variation between actual and normal gas usage captured in the WNAR under Staff's ranking method reduces the financial impact to customers. (footnote omitted)

In this case, GO-2019-0058, the Commission recognized the importance of the ranked normal process of the Staff in calculating weather normalization adjustments when it ordered Spire to file tariff sheets based on Staff's ranked method for determining daily normal weather.[11]

Q. Is the determination of the ranked normal heating degree days a complicated process?

A. No. The 365 normal heating degree days ("HDD") will be determined in this rate case. With an annual filing, the normal weather values would only have to be assigned to the days once a year. With the current WNAR, a computer program should have already been developed to do this assignment of weather to the days.

Q. Spire also stated that the WNAR required an unbilled calculation that made the mechanism complicated. What is an unbilled calculation?

A. As previously described, a billing month contains usage from 18 billing cycles with usage spread across two or three calendar months. All utilities do an unbilled

[11] GO-2019-0058, *Report and Order*, page 13.

calculation to estimate calendar month usage and revenues. When looking at my Schedule LMM-R-2, the top right shaded triangle is the "unbilled" portion of December. There are various ways of estimating this unbilled usage but the one common aspect of these methods are that they are all estimates.

Part of determining calendar usage is the allocation of the billing cycle usage of the December billing month between November and December. The simplest way to allocated between the months is to calculate a simple daily average usage for each billing cycle and allocate the appropriate number of days to each month. More complicated methods would incorporate weather in allocating between the months. Even though the utility has measured usage for the billing month, the process of allocating known usage between calendar months is also an estimate.

As long as usage for a time period different from the calendar month has existed, there has been a need for this type of analysis to determine calendar month usage and revenues. The estimation process can be simple or complicated and occurs whether a WNAR exists or not.

Q. Is this process necessary for the WNAR?

A. No, it is not. The WNAR is calculated based on billing cycles and billing months. Any unbilled calculation is merely done for internal Spire processes and was done prior to the WNAR and will continue even if there is a RNA.

Q. The other issue identified was that the mechanism did not provide as close a correlation to volumetric variances as Spire anticipated. Can you explain?

A. I sent several data request to Spire to try to understand what this meant. The best explanation that I received was in Spire's response to OPC data request 8000.3, where it stated:

> The mechanics of how the WNAR mechanism works *does not anchor the calculation to any defined set of billing determinants* but

> instead is calculated by billing cycle, using ranked degree days, and an unbilled calculation. (emphasis added)

Q. What is your understanding of this answer?

A. Basically, Spire expected that the WNAR would result in it receiving the residential class rate revenues set in the rate case. When it did not result in the normalized revenues from the rate case, then it is Spire's belief that there is something wrong with the WNAR.

Q. Do you agree that there is something wrong with the WNAR when it does not result in revenues as set in the last rate case?

A. No. Its design purpose is not to result in the billing determinants that were set in the last rate case. In fact, the Commission in its Report and Order approving the WNAR realized that there would be some variances when stated that annual natural gas usage was 95% correlated with annual HDD.[12] It is unrealistic to expect the WNAR to result in the billing determinants in the last rate case.

Q. **Did Spire provide any measurements of the volumetric variances that caused it concern?**

A. No. However, it did provide the following variances in the revenues as compared to its budget.

**

**

---

[12] GR-2017-0215, *Report and Order*, page 83.

Q. Given just the numbers in this table, what is your conclusion?

A. Given the limited information in this table, I conclude that the WNAR is giving consistent results across these two years. The difference between the WNAR adjusted revenues is 0.13% for Spire East and 0.68% for Spire West.

The real issue for Spire is that the WNAR Adjusted amount is not the same as its Budget. As shown in the table above, the WNAR adjusted amount is lower than the budgeted amount.

Q. Does this imply that there is a problem with the WNAR?

A. No. Since the WNAR was almost the same for both of these two years, I would say, given the limited information in this table, that the problem may lie with the budget, not the WNAR.

Q. Spire witness Selinger states that the WNAR caused anomalies opposite of the mechanism's intended purpose such as warmer than normal temperatures resulting in Spire refunding revenues.[13] Should this concern the Commission?

A. No. Data request responses provided to OPC data requests revealed that these "anomalies" were instances where the billing month weather adjustment was different that the adjustment that would be made using calendar month weather as previously shown in this testimony. Spire stated in response to OPC data request 8001:

> When performing the WNAR calculation for the month in question (December 2019), the mechanics of the WNAR mechanism created a situation where the Company was in a give-back position, even though the weather that month was warmer than normal.

The "WNAR calculation" referred to was a December *billing* month calculation. The "weather that month" was the weather for the *calendar* month. As described above, the weather for the billing month was different than the calendar month

[13] Direct testimony of Spire Witness Wesley E. Selinger, page 28.

which created what Mr. Selinger labeled an "anomaly." The billing month weather will always be different from the calendar month weather. In this instance, the difference resulted in a give-back position because of extreme weather that occurred in late November that was not reflected in the December calendar month weather measures but was in the December billing month.

Q. Should these "issues" and "anomalies" provided by Spire adequate reasons to replace the WNAR with a RNA?

A. No. The calculation of the WNAR takes little effort and time. What Spire sees as "issues" are not a reason to shift from a mechanism that accounts for fluctuations of revenue due to weather and, in part, due to conservation to a mechanism that does not explicitly take into account either weather or conservation.

What Spire labels an "anomaly" is not truly an anomaly or a failure of the WNAR. The failure to understand the difference between billing months and calendar month weather is not a reason for the Commission to end the WNAR.

In addition, the consistency in the WNAR revenues provides that the WNAR is working as the Commission intended when it approved it in the last rate case.

<u>Staff Alternative RNA Witnesses Sarah L.K. Lange and Michael L. Stahlman</u>

Q. What rationale did Staff provide for switching from the WNAR to a RNA?

A. The only rational Staff gives is it that it believes that the WNAR is limited to fluctuations in weather only.[14]

---

[14] *Staff Report, Class Cost of Service*, page 38.

Q. Does the mechanism approved by the Commission have to account for weather fluctuations and all conservation efforts?

A. No. As I have previously testified, § 386.266.3 says a gas corporation can apply for a mechanism that accounts for fluctuations in either weather, conservation, ***or*** both.

Q. Did Staff provide an explanation for why it was necessary for Spire to be insulated from the impacts of conservation?

A. No, it did not.

Q. Did Staff testify that there were any problems with the operation of Spire's WNAR?

A. No, it did not. However, it did bring up issues that occurred with another company's WNAR when a third party failed to record daily temperatures.[15]

Q. How likely is it that a third party would fail to record the daily temperatures used by Spire East and Spire West?

A. Very unlikely. Spire East uses weather recorded at the St. Louis Lambert International Airport Weather Station and Spire West uses weather recorded at the Kansas City International Airport Weather Station.

Q. Does Staff say that it has an issue with using ranked normals?

A. While it does bring up that there has been issues with ranking of weather,[16] it does not say that Staff has an issue with the ranked normals. In fact, it has used ranked normals since the 1990s and defended the use of ranked normals recently in Spire's WNAR in case GO-2019-0058.

[15] *Id.*, pg. 39.
[16] *Id.*

Q. What are differences between Staff's proposed RNA and Spire's proposed RNA?

A. I have not conducted an exhaustive review. However, the most notable is that Staff and Spire have different block breaks for the beginning of the second block of usage for the residential class and a range of usage for the SGS class.

Q. What block breaks is Staff proposing and how were the breaks determined?

A. After its review of customer usage data specific to Spire, Staff is proposing a block breakpoint of 50 Ccf for the residential class and a beginning block break of 200 and an ending block break of 500 Ccf for the small general service class.[17] Staff looked at the number and percentage of customers for Spire West and Spire East that had usage at or below increments of 10 Ccfs and therms for the residential and increments of 100 Ccf and therms for SGS customers. From its review of this information, Staff is proposing the 50 Ccf block break for residential customers and the RNA be calculated using the usage between 201 and 500 Ccf for SGS customers.

Q. What block breaks is Spire proposing and how were the breaks determined?

A. Spire recommends block breaks of 30 Ccf for the residential class and 100 Ccf for the SGS class with no upper limit. Spire did not provide testimony on how it came up with these block breaks. In response to OPC's data request 8004 for a detailed explanation of how these block breaks were determined, Spire stated:

> Prior to its last rate case, Spire Missouri's Eastern service territory employed a weather-mitigated rate design for Residential customers with a block break point at 30 therms. The Company does not believe circumstances have changed since that case to a degree that would make this block break point no longer appropriate. As the proposed mechanism is designed to address variations in usage due to weather and conservation pursuant to Missouri Revised Statute

[17] *Id.*, pages 40-42. While the Staff report states 300 to 500 Ccfs, the table shows usage from 201 Ccf through 500 Ccf. It was confirmed in conversations with Sarah Lange of Staff that this was Staff's intent.

> 386.266 (3), the Company feels this is the appropriate block break point for the proposed mechanism. In addition, Missouri regulatory stakeholders approved a similar mechanism for Ameren Missouri, a Missouri gas utility situated similarly to Spire's East and West service territories, in Case No. GR-2019-0077. Spire relied on this prior case guidance in designing the proposed RNA block break for its SGS class.

Q. What would be the impact of using a block break of 50 Ccf as proposed by Staff instead of Spire's 30 Ccf block break?

A. The revenue requirement that would be guaranteed is smaller the higher the block break. Therefore, Spire would be guaranteed less revenue if the 50 Ccf block is used.

Q. What would be the impact of only including the usage between 200 and 500 Ccf of the SGS class as Staff proposed over using a block break of 100 Ccf recommended by Spire?

A. Using Staff's block of 200 Ccf through 500 Ccf would guarantee less revenue than Spire's proposed block break of 100 Ccf with no upper limit. Staff's segment of usage would also result in less double recovery of revenues for customers that switch rates.

Q. Would you summarize your rebuttal testimony regarding a rate mechanism to account for fluctuations in revenues due to either weather, conservation, or both?

A. The Commission decision in case GR-2017-0214 found that in that case:[18]

> Spire Missouri has not provided evidence that the RSM it proposed is needed for either revenue recovery (Spire Missouri has had no difficulty in meeting its revenue requirement) or to incentivize conservation. Further, the RSM as proposed by Spire Missouri is not consistent with the statutory requirements that allow the Commission to approve a mechanism for adjusting rates outside of a general rate proceeding "to reflect the non-gas revenue effects of

[18] Report and Order, page 83.

> increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both" because it would adjust rates for all changes in average customer use, not only due to variations in weather and/or conservation.

In this case Spire, once again, does not justify why the Commission should approve an interim rate mechanism that accounts for weather or conservation. It currently has a mechanism that accounts for fluctuations in weather and some conservation but it wants to go further, again without justification, asking for a mechanism that assures that it will receive a set amount of revenue from its residential and small general service customers.

Staff does not justify why a mechanism is necessary or why the current mechanism should be discarded. Its proposal leaves some risk on Spire but still guarantees Spire revenue. Its recommended mechanism would recover or return all changes in revenue regardless of what cause the change. It does not limit the cause of the change of revenues to weather and conservation as allowed by statute.

For these reasons, the Commission should not approve a RNA for Spire. If the Commission believes a mechanism accounting for weather and some conservation is necessary for Spire, it should approve the WNAR I recommended in my direct testimony.

<u>Concluding Summary</u>

Q. Would you summarize your rebuttal testimony?

A. The Commission should not approve Spire's proposed tariff sheet language regarding free extension of service to customers at the discretion of Spire.

Spire should provide for inclusion in its tariff sheets an accurate description of the current process for estimating usage rather than including a description of the information that information that is used to estimate usage.

Until Commission rules are effective, the Commission should not approve the voluntary customer program proposed by Spire where customers can pay more with the expectation that the funds will be used to purchase RNG for their consumption. As required by recently passed legislation, Commission rules should be adopted prior to the offering of such a program through Spire.

Because of the high incremental cost of RNG over traditional gas supply, the Commission should not allow Spire to procure up to 5% of its gas supply from renewable sources. Spire has not provided information on the availability or potential cost impact of the Commission allowing up to 5% of its supply to be RNG. By allowing the cost to be passed through the PGA, the Commission would be increasing the cost risk to customers with no impact on Spire.

Finally, the Commission should not approve any rate adjustment mechanism that has been proposed to account for fluctuations in weather and conservation for Spire because it has not provided any testimony showing a need for such a mechanism or why the Commission should approve a mechanism.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Spire Missouri
GR-2021-0108

Response to Office of Public Counsel (OPC) Data Request 8000

On page 28 of his direct testimony, Selinger states that the WNAR has had issues.

Please provide 1) a detailed description of each issues including, but not limited to, why it was an issue for the WNAR; and 2) how Spire's proposed RNA will eliminate each issue.

Requested by John Clizer and Lena Mantle (john.clizer@opc.mo.gov and lena.mantle@opc.mo.gov).

Response: The Company believes that the WNAR mechanism is more complicated than it needs to be. The mechanism is updated semi-annually and requires four (4) separate rate components be always in place (i.e. 2 CWNA and 2 SRR rates). The mechanism is calculated by billing cycle, uses ranked degree days, and requires an unbilled calculation. The mechanism has also not provided as close a correlation to volumetric variances as the Company anticipated. Please also see the Company's response to OPC Data Request 8001 for further explanation of this testimony.

The Company's proposed RNA will be tied to billing determinants set in this rate case. In addition, the RNA rates will be calculated on an annual basis and will not require heating degree day information.

Signed by: Wesley Selinger

Billing Month vs Calendar Month
Actual 2019 Billing Cycle Read Dates
Spire East

Bill Cycle	Read Date Begin	Read Date End	HDD Actual	HDD Norm
1	31-Oct	1-Dec	729	574
2	3-Nov	2-Dec	679	538
3	4-Nov	3-Dec	692	561
4	5-Nov	4-Dec	704	585
5	6-Nov	5-Dec	705	594
6	7-Nov	8-Dec	756	658
7	10-Nov	9-Dec	692	608
8	11-Nov	10-Dec	707	635
9	12-Nov	11-Dec	739	680
10	14-Nov	15-Dec	732	696
11	17-Nov	16-Dec	683	663
12	18-Nov	17-Dec	697	684
13	19-Nov	18-Dec	716	717
14	20-Nov	19-Dec	739	762
15	21-Nov	22-Dec	780	818
16	24-Nov	25-Dec	797	864
17	25-Nov	26-Dec	797	864
18	26-Nov	29-Dec	823	902

October

	29	30	31
Actual HDD	19	27	31
Normal HDD	18	20	24

NOVEMBER — November Calendar Month

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Actual HDD	22	21	18	14	18	22	30	35	17	10	35	49	38	30	30	28	24	20	18	17	12	27	28	20	10	15	19	32	26	17
Normal HDD	19	18	14	5	13	19	25	32	11	1	31	40	35	28	27	24	20	17	12	10	3	22	24	16	0	7	15	29	21	9

DECEMBER — December Calendar Month

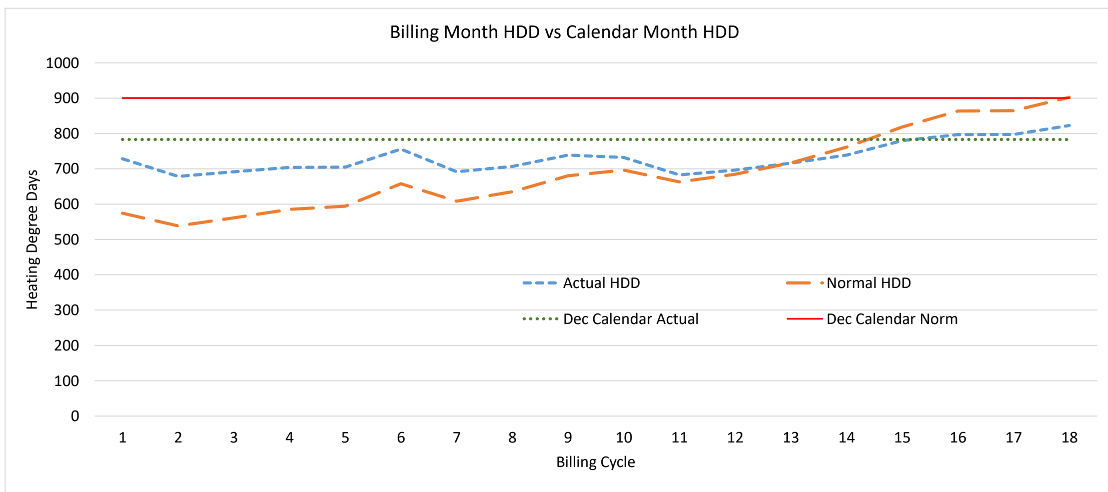
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Actual HDD	24	31	27	19	20	24	30	18	25	37	30	24	25	32	39	38	40	40	29	29	26	25	18	15	12	8	23	13	14	27	28
Normal HDD	26	37	30	22	23	25	35	20	28	40	36	25	27	38	45	42	50	57	34	33	29	27	21	18	12	5	24	14	17	31	32

December Calendar
Actual HDD 783
Normal HDD 900

= November Billing Month Usage

D = December Billing Month Usage

= December Unbilled



LMM-R-2

Exhibit No.:	
Issue(s):	*Weather Data*
Witness:	*Seoung Joun Won, PhD*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*GO-2019-0058 and GO-2019-0059*
Date Testimony Prepared:	*November 16, 2018*

MISSOURI PUBLIC SERVICE COMMISSION

COMMISSION STAFF DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

SEOUNG JOUN WON, PhD

SPIRE MISSOURI, INC., d/b/a SPIRE EAST
CASE NO. GO-2019-0058

AND

SPIRE MISSOURI, INC., d/b/a SPIRE WEST
CASE NO. GO-2019-0059

Jefferson City, Missouri
November 2018

TABLE OF CONTENTS OF

DIRECT TESTIMONY

OF

SEOUNG JOUN WON, PhD

SPIRE MISSOURI, INC., d/b/a SPIRE EAST
CASE NO. GO-2019-0058

AND

SPIRE MISSOURI, INC., d/b/a SPIRE WEST
CASE NO. GO-2019-0059

DIRECT TESTIMONY

OF

SEOUNG JOUN WON, PhD

SPIRE MISSOURI, INC., d/b/a SPIRE EAST
CASE NO. GO-2019-0058

AND

SPIRE MISSOURI, INC., d/b/a SPIRE WEST
CASE NO. GO-2019-0059

Q. Please state your name and business address.

A. My name is Seoung Joun Won and my business address is Missouri Public Service Commission, P. O. Box 360, Jefferson City, Missouri 65102.

Q. Who is your employer and what is your present position?

A. I am employed by the Missouri Public Service Commission ("Commission") and my title is Regulatory Economist III in the Tariff/Rate Design Department, Commission Staff Division.

Q. What is your educational background and employment experience?

A. I received my Bachelor of Arts, Master of Arts, and Doctor of Philosophy in Mathematics from Yonsei University in Seoul, South Korea, and earned my Doctor of Philosophy in Economics from the University of Missouri - Columbia.

Prior to joining the Commission, I taught both undergraduate and graduate level mathematics in the Korean Air Force Academy and Yonsei University for 13 years. I served as the Director of the Education and Technology Research Center at NeoEdu, an IT education company in South Korea, for five years. I have been employed at the Commission since May 2010 as a regulatory economist. For more details about my credentials, backgrounds, and case participations, please see attached Schedule SJW-1.

EXECUTIVE SUMMARY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to explain Staff's weather data used for Spire Missouri Inc. d/b/a Spire's ("Spire") weather normalization adjustment rider (WNAR).

Q. Which aspects of the weather data are you going to explain?

A. I am explaining: (1) weather variables used in actual and normal weather data sets, and (2) a ranked average method calculating normal weather data.

WEATHER VARIABLES

Q. What are the weather variables that Staff used for WNAR?

A. The weather variables used for WNAR are actual daily maximum temperature ("T_{max}") and daily minimum temperature ("T_{min}") observations. Staff used these daily temperatures to develop a set of mean daily temperature (MDT)[1] values. Natural gas sales are predominantly influenced by "ambient air temperature,"[2] so MDT and the derivative measure, heating degree days (HDD),[3] are the measures of weather used in adjusting test year natural gas sales. HDDs were originally developed as a weather measure that could be used to determine the relationship between temperature and gas usage. HDDs are based on the difference of MDT from a comfort level of 65°F. HDDs are calculated as the difference between 65°F and MDT when MDT is below 65°F, and are equal to zero when MDT is above 65°F. Actual and normal HDDs are calculated for each day in the test period that applies to Spire's service territory.

---

1 By National Climatic Data Center convention, MDT is the average of daily maximum temperature (T_{max}) and daily minimum temperature (T_{min}) e.g. MDT = (T_{max} + T_{min}) /2

2 Ambient air temperature is the outside temperature of the surrounding air without taking into account the humidity or wind in the air.

3 Where MDT < 65°F, HDD = 65 – MDT; otherwise, HDD = 0.

Q. What is the data source of Staff's weather variables?

A. Staff obtained weather data from the Midwest Regional Climate Center (MRCC).[4] Weather data of St Louis Lambert International Airport ("STL") and Kansas City International Airport ("MCI") were used for the service territories of Spire Missouri East and Spire Missouri West, respectively.

Q. What is normal weather?

A. According to the National Oceanic and Atmospheric Administration ("NOAA"), a climate "normal" is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[5] For the purposes of normalizing the test year gas usage and revenues with the same time period determined in the rate cases GR-2017-0215 and GR-2017-0216, Staff used the adjusted T_{max} and T_{min} daily temperature series for the 30-year period of 1987 through 2016 at STL and MCI.

Q. What is the adjusted daily temperature series?

A. In developing climate normal temperatures, NOAA focuses on the monthly maximum and minimum temperature time series to produce the serially-complete monthly temperature (SCMT) data series.[6] Staff utilized the most recent SCMT for the period of 1987 through 2010 from the data set that was published in July 2011 by the National Climatic Data Center (NCDC) of NOAA. For the period of 2011 through 2016, Staff utilized the T_{max} and T_{min} daily temperature series that NOAA make available at the MRCC website.[7]

---

[4] https://mrcc.illinois.edu/CLIMATE/

[5] Retrieved on October 17, 2013, https://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals

[6] Retrieved on October 17, 2013, http://www1.ncdc.noaa.gov/pub/data/normals/1981-2010/source-datasets/. The SCMT, computed by NOAA, includes adjustments to make the time series of daily temperatures homogeneous.

[7] https://mrcc.illinois.edu/CLIMATE/

Q. Why did Staff use NOAA's SCMT?

A. There may be circumstances under which inconsistencies and biases in the 30-year time series of daily temperature observations occur, (e.g. such as the relocation, replacement, or recalibration of the weather instruments). Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. NOAA accounted for documented and undocumented anomalies in calculating its SCMT.[8] The meteorological and statistical procedures used in NOAA's homogenization for removing documented and undocumented anomalies from the T_{max} and T_{min} monthly temperature series is explained in a peer-reviewed publication.[9]

RANKED AVERAGE METHOD

Q. What is Staff's method to calculate normal weather variables?

A. Staff used a ranked average method to calculate daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating "normal extremes." Staff ranked MDTs for each month of the 30-year history from hottest to coldest and then calculated the normal daily temperature values by averaging ranked MDTs for each rank, irrespective of the calendar date. In other words, the daily normal temperature for a given date in the accumulation period of WNAR is the average of MDTs that have the same rank in the month for each year in the 30-year normal period (1987 - 2016).

Therefore, as a result of the ranking process, the normal most extreme temperature of the month is the average of the most extreme temperatures in each of the months of the

[8] Arguez, A., I. Durre, S. Applequist, R. S. Vose, M. F. Squires, X. Yin, R. R. Heim, Jr., and T. W. Owen, 2012: NOAA's 1981-2010 U.S. Climate Normals: An Overview. Bulletin of the American Meteorological Society, 93, 1687-1697,

[9] Menne, M. J., and C. N. Williams, Jr., (2009) Homogenization of temperature series via pairwise comparisons. *J. Climate*, **22**, 1700-1717.

30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each of the month, and so forth. In addition, the daily normal temperature is decided by the rank of the actual MDTs in the month although the set of daily normal temperature values for each month is not changed.

Q. Why does Staff use the ranked average method?

A. NOAA's daily normal temperatures are not directly usable for Staff's purposes. NOAA's dated average method calculates a simple arithmetic mean of MDTs of the same calendar date for each year in the 30-year normal period. Staff's calculated daily normal temperatures are based on the rankings of the actual temperatures of the accumulation period and the daily actual temperatures do not follow smooth patterns from day to day.

In other words, the NOAA daily normal temperatures and HDD values are derived by statistically "fitting" smooth curves through these monthly values. As a result, the NOAA daily normal HDD values reflect smooth transitions between seasons and do not directly relate to the 30-year time series of MDT as used by Staff. However, in order for Staff to develop adjustments to normal HDD for gas usage, Staff must calculate a set of normal daily HDD values that reflect the actual daily and seasonal variability. More details of a ranked average method for normal weather are explained in a peer-reviewed publication which I co-authored and attached Schedule SJW-2.[10]

Continued on next page.

[10] Won, S. J., Wang, X. H., & Warren, H. E. (2016). Climate normals and weather normalization for utility regulation. Energy Economics, 54, 405-416.

Figure 1 Daily Average Temperature Normal – STL

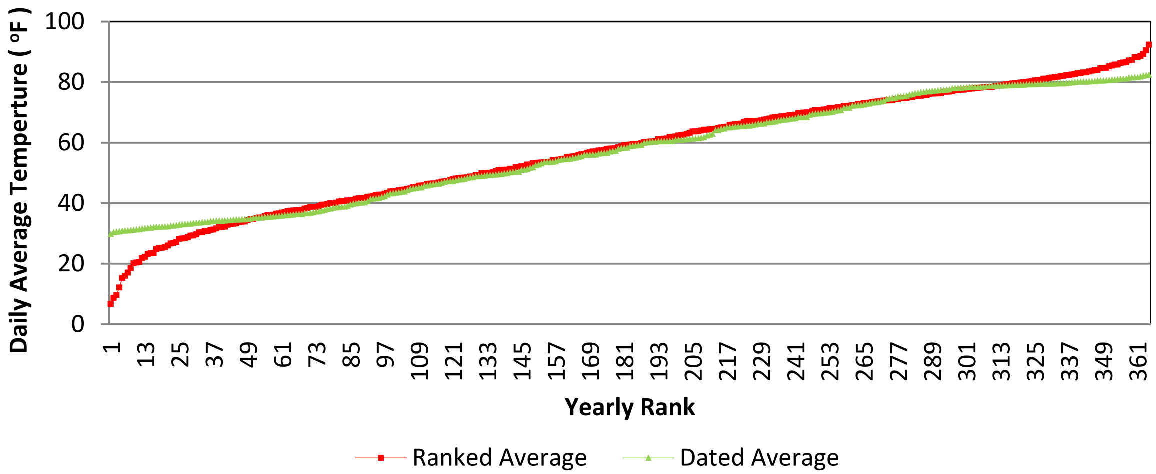
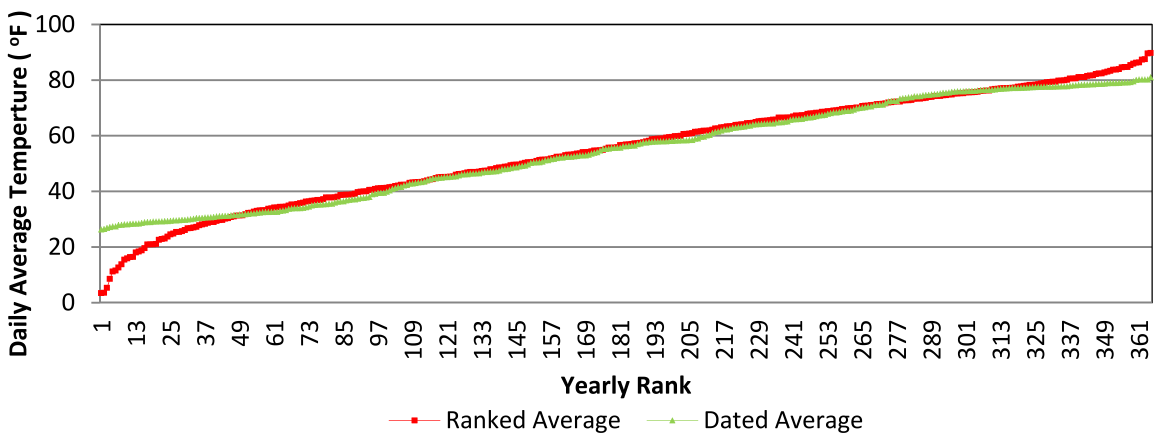


Figure 2 Daily Average Temperature Normal – MCI



Q. What is the evidence that a ranked average method is more appropriate than a dated average method?

A. The evidence is demonstrated by a comparison of the results of the two different methods. If the ranked average method is used, the range of daily temperatures is 7°F through 92°F and 3°F through 90°F in STL and MCI, respectively. In contrast, if the dated average method is used, the range of daily temperatures is 30°F through 82°F and 26°F through 81°F in STL and MCI, respectively. Therefore, the ranked average method produces a more realistic daily temperature variation. Figure 1 and Figure 2 show the distribution of daily normal temperature series of STL and MCI.

Q. Why should the rank of daily normal temperature match to the rank of actual MDTs of the accumulation period?

A. According to the formula in Spire's WNAR tariff, the relationship between daily temperatures and daily gas usages should be preserved as it was calculated in the most recent rate cases. If daily normal weather values are not properly assigned to the associated rank of each month actual MDTs, the relationship between temperature and gas usage is distorted so that the calculation of WNAR would be biased. This is further discussed by Staff Witness Michael Stahlman.

In addition, if daily normal temperature values would not be assigned to the accumulation period, it would calculate invalid billing cycle HDDs. For instance, the leap day weather variables should be considered only in the case the time periods include leap days in the case of a billing cycle that includes the last day of February and the first day of March.

CONCLUSION

Q. What is your conclusion of this direct testimony?

A. Staff recommends that the Commission order the use of Staff's ranked average method actual and normal weather data for Spire's WNAR adjustment.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Spire Missouri, Inc. d/b/a Spire's Request to Decrease WNAR	))	Case No. GO-2019-0058
		and
In the Matter of Spire Missouri, Inc.'s d/b/a Spire's Request to Increase Its WNAR	))	Case No. GO-2019-0059

AFFIDAVIT OF SEOUNG JOUN WON, PhD

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW SEOUNG JOUN WON, PhD and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Direct Testimony*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

SEOUNG JOUN WON, PhD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 15th day of November 2018.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D Suzie Mankin
Notary Public

Credentials and Background of
Seoung Joun Won

I am currently employed as a Regulatory Economist III in the Tariff and Rate Design Department of the Commission Staff Division of the Missouri Public Service Commission ("Commission"). I have been employed at the Commission since May 2010.

I received my Bachelor of Arts, Master of Arts, and Doctor of Philosophy in Mathematics from Yonsei University in Seoul, South Korea, and earned my Doctor of Philosophy in Economics from the University of Missouri - Columbia. Also, I passed several certificate examinations for Finance Specialist in South Korea such as Enterprise Resource Planning Consultant, Financial Risk Management, Derivatives Consultant, and Financial Planner.

Prior to joining the Commission, I taught both undergraduate and graduate level mathematics at the Korean Air Force Academy and Yonsei University for 13 years. I served as the Director of the Education and Technology Research Center at NeoEdu, an IT education company in South Korea, for 5 years. I have been employed at the Commission since May 2010 as a regulatory economist.

My duties at the Commission include managing weather data, calculating normal weather, conducting weather normalization, analyzing revenues and cost of services, developing rate designs, and supporting economic and statistical analysis.

List of Previous Testimony Filed
Seoung Joun Won

Case/File Number	Company	Issue
ER-2010-0355	Kansas City Power & Light Co.	Weather Variables Revenue
ER-2010-0356	KCP&L Greater Missouri Operations Co.	Weather Variables
GR-2010-0363	Union Electric Co., d/b/a Ameren Missouri	Weather Variables
ER-2011-0028	Union Electric Co., d/b/a Ameren Missouri	Weather Variables Revenue
ER-2011-0004	Empire District Electric Co.	Weather Variables Revenue
HR-2011-0028	Veolia Energy Kansas City, Inc.	Weather Variables
ER-2012-0166	Union Electric Co., d/b/a Ameren Missouri	Weather Variables Revenue
ER-2012-0174	Kansas City Power & Light Co.	Weather Variables Revenue
ER-2012-0175	KCP&L Greater Missouri Operations Co.	Weather Variables
ER-2012-0345	Empire District Electric Co.	Weather Variables Revenue
GR-2013-0171	Laclede Gas Co.	Weather Variables
HR-2014-0066	Veolia Energy Kansas City, Inc.	Weather Variables Weather Normalization
GR-2014-0086	Summit Natural Gas of Missouri, Inc.	Weather Variables
GR-2014-0152	Liberty Utilities (Midstates Natural Gas) Corp.	Weather Variables
EC-2014-0223	Noranda Aluminum, Inc., et al, Complaint v. Union Electric Co., d/b/a Ameren Missouri	Weather Variables
ER-2014-0258	Union Electric Co., d/b/a Ameren Missouri	Weather & Normalization Net System Input
ER-2014-0351	Empire District Electric Co.	Weather & Normalization Net System Input
ER-2014-0370	Kansas City Power & Light Co	Weather & Normalization Net System Input
ER-2016-0023	Empire District Electric Co.	Weather & Normalization Net System Input

cont'd List of Previous Testimony Filed
Seoung Joun Won

Case/File Number	Company	Issue
ER-2016-0156	KCP&L Greater Missouri Operations Co.	Weather & Normalization Net System Input
ER-2016-0179	Union Electric Co., d/b/a Ameren Missouri	Weather & Normalization Net System Input
ER-2016-0285	Kansas City Power & Light Co	Weather & Normalization Net System Input
GR-2017-0215	Laclede Gas Co. Spire Missouri, Inc	Weather Variables
GR-2017-0216	Missouri Gas Energy (Laclede) Spire Missouri, Inc	Weather Variables
GR-2018-0013	Liberty Utilities (Midstates Natural Gas) Corp.	Weather Variables
ER-2018-0145	Kansas City Power & Light Co	Weather & Normalization Net System Input
ER-2018-0146	KCP&L Greater Missouri Operations Co.	Weather & Normalization Net System Input

Work Related Publication

Won, Seoung Joun, X. Henry Wang, and Henry E. Warren. "Climate normals and weather normalization for utility regulation." *Energy Economics* (2016).

Energy Economics 54 (2016) 405–416

Contents lists available at ScienceDirect

Energy Economics

journal homepage: www.elsevier.com/locate/eneeco

Climate normals and weather normalization for utility regulation☆

Seoung Joun Won [a,*], X. Henry Wang [b], Henry E. Warren [a]

[a] Missouri Public Service Commission, P.O. Box 360, Jefferson City, MO 65102-0360, United States
[b] Department of Economics, University of Missouri, Columbia, 909 University Avenue Columbia, MO 65211-6040, United States

ARTICLE INFO

Article history:
Received 6 December 2014
Received in revised form 9 December 2015
Accepted 13 December 2015
Available online 14 January 2016

JEL classification:
C46
Q41
Q48

Keywords:
Climate normals
Weather normalization
Rate cases
Utility regulation

ABSTRACT

In the regulation of natural gas and electric utilities, the determination of rate revenues commonly involves a sales adjustment to reflect the difference between actual weather and normal weather. This adjustment process, commonly known as weather normalization, is required to properly determine a set of rates which yields the revenue requirement under the assumption of normal weather. Normal weather values that characterize long-term weather patterns are critical component of weather normalization. Conventionally, normal weather values are calculated using the Standard Climate Normal (SCN). The SCN for any given calendar day is the 30-year average of the associated weather observations for that calendar day. In the regulatory process the SCN can inadvertently introduce biases in the weather normalization adjustment. This study investigates the sources and mitigation of these biases.

1. Introduction

In the United States, rates for regulated natural gas and electric utilities (energy utilities) are periodically reset through administrative proceedings commonly known as rate cases. In a rate case, rates are established which recover the revenue requirement. However, an energy utility's sales vary year to year. This variation can occur for many reasons: weather, economic conditions, and other events that influence customer behavior (Dergiades and Tsoulfidis, 2008). In the regulatory process, the actual energy sales need to be adjusted for any unusualness during the test year (Monts et al., 1989).[1]

The temperature pattern is one of the primary determinants of energy usage and revenues for most energy utilities (Bower and Bower, 1985). Unusual levels of energy sales, due to an unusual temperature pattern, must be adjusted to levels consistent with the normal temperature pattern (Elkhafif, 1996). For the rate design to be just and reasonable this weather normalization adjustment is determined using a model that quantifies the relationship between sales and temperature.

In the weather normalization of test year energy sales, developing a data set of normal weather values that characterizes long-term weather patterns in the utility service territory is critical. Weather-normalized energy sales are calculated using weather during the test year that is adjusted to normal. In this calculation, daily normal weather values replace actual daily weather values during the test year in a model of energy sales. Depending on the model of energy sales, the data set of normal weather may need to reflect a more complete set of statistical properties, including monthly and yearly temperature variation. If the statistical properties of normal weather are inconsistent with the statistical properties of the test year weather, then the subsequent calculation of weather normalized sales will be biased. The total U.S. energy utility operating revenue was over $300 billion in 2009 (US Census Bureau, 2012).[2] A weather normalization adjustment to utility revenue may be more than 2% of annual operating revenues (Croucher, 2011). So, any miscalculation in the weather normalization adjustment to sales could have a significant impact on rate.

Conventionally, the Standard Climate Normal (SCN) is used for determining the daily normal weather values. Climate normals are based upon the average of associated weather variables in a certain time period. According to the National Oceanic and Atmospheric

☆ Disclaimer: The views expressed in this paper are those of the authors and do not necessarily reflect the views of the Missouri Public Service Commission.

* Corresponding author.
E-mail addresses: seoungjoun.won@psc.mo.gov (S.J. Won), WangX@missouri.edu (X.H. Wang), henry.warren@psc.mo.gov (H.E. Warren).

[1] A test year in the context of a utility rate case is a consecutive 12-month period used to calculate normalized and annualized costs and revenues which serve as a basis for calculating appropriate new rates. A test year could be a forward test year using projected data or a historical test year using verifiable actual data with some adjustments for known and measurable changes. Normal weather is appropriate for either type of test year, because the historical time series uses verifiable actual data for calculating normal weather, and it is assumed to be the most likely expectation for future years in which the new rates will be effective.

[2] See http://www.census.gov/compendia/statab/cats/energy_utilities.html.

http://dx.doi.org/10.1016/j.eneco.2015.12.016
0140-9883/

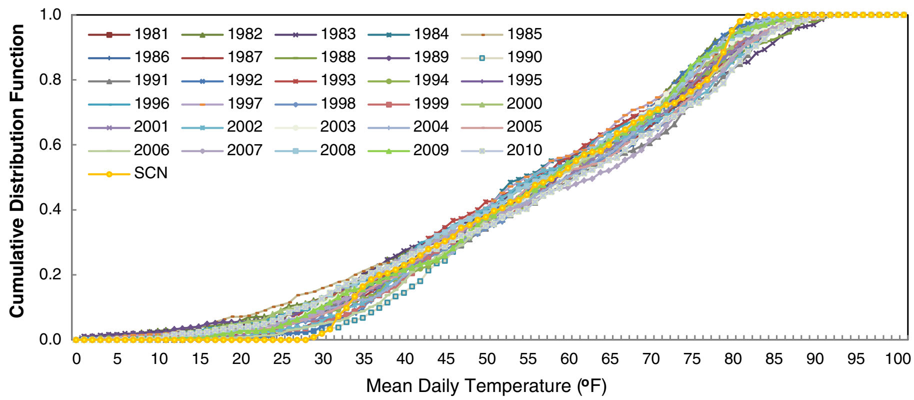


Fig. 1. Cumulative distribution functions of each year MDT and the daily SCN temperatures (1981–2010).

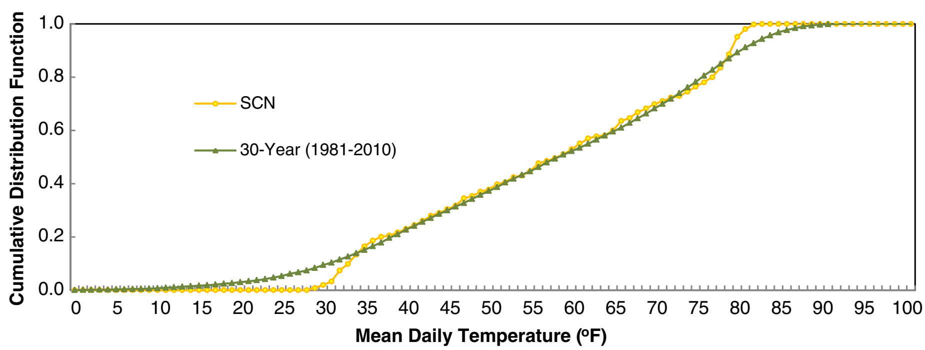


Fig. 2. Cumulative distribution functions of the daily temperature SCN and the 30-year (1981–2010) MDT.

Administration (NOAA), the SCN is defined as the arithmetic mean of a climatological element computed over 30-year period, usually three consecutive decades.[3] The SCN has also been the international standard for calculating normal weather for more than 70 years (Livezey and Hanser, 2013).

For several years, there has been ongoing debate concerning the SCN in energy utility rate design (Angel et al., 1993; Livezey et al., 2007; Livezey and Hanser, 2013). Recently, NOAA held a workshop on alternative climate normal calculations and the subsequent impact to the energy industry rates and revenues (Arguez et al., 2013). These issues are related to climate changes. However, there are more fundamental problems to define normal weather for the utility regulation.

Normal weather variables are statistical expectations of weather variables calculated using a long-term historical data. According to the National Climate Data Center (NCDC) the current daily SCN is based upon a 30-year (1981–2010) average of the yearly associated weather observations for the calendar day. If the goal is to define the most plausible temperature of a given calendar date using historical data, the daily SCN provides a statistically well-defined expectation. However, if we want to calculate the most plausible set of temperature values for the 365 days in a year, the suitability of the 365 daily SCN temperature values is questionable. Although each daily SCN is a good expectation for each calendar day, the set of 365 daily SCN values may not be the expectation for the days in an SCN year. Fig. 1 contains the 30 cumulative distribution functions of the mean daily temperatures (MDT) for the years 1981–2010 and the daily SCN for the normal period 1981–2010.

Fig. 1 illustrates that the annual proportion of MDT below 28 °F or above 82 °F, ranges from 5% to 25% of the calendar days in the years 1981–2010, but none of the 365 daily SCN temperatures for 1981–2010 are in those ranges. Since these temperatures are significant in determining daily energy sales and load forecasts, use of the daily temperature SCN in calculating weather normalized sales in utility rate cases will result in lower winter and summer sales. The source of this bias can be defined in terms of distribution similarity.

According to the Finkelstein–Schafer statistic (Finkelstein and Schafer, 1971), if any number, n, observations of a weather index $X_1, X_2, \ldots, X_n$ are available, a monotonic increasing function, $F(x)$, defined by

$$F(x) = (\text{number of } X_i \text{ such that } X_i \le x)/n.$$

$F(x)$ is a cumulative distribution function (CDF) based on the time series of the weather index with size n. The comparison statistics, FS, between CDF for the long-term (F_{LT}) which is used for calculating the climate normal and CDF for the climate normal (F_{CN}) are calculated by the following equation:

$$FS(F_{LT}, F_{CN}) = \int |F_{LT}(x) - F_{CN}(x)| dx.$$

We define the temperature distribution bias of a climate normal as the FS statistics. In Fig. 2, it can be seen that the SCN series has significant bias in the lower temperatures (25 °F–35 °F) and the higher temperatures (75 °F–85 °F).

This study investigates the effect of the SCN bias in the weather normalization process in the economics of electric utility rate design. An unbiased alternative procedure is developed for calculating daily normal temperatures. Weather normalization adjustments to energy sales and revenues are computed using the SCN and the alternative procedure. The results show that the alternative procedure of daily normal test year temperatures are preferred to the SCN because their distribution is closer to actual daily temperature distribution and there is a

[3] See http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html.

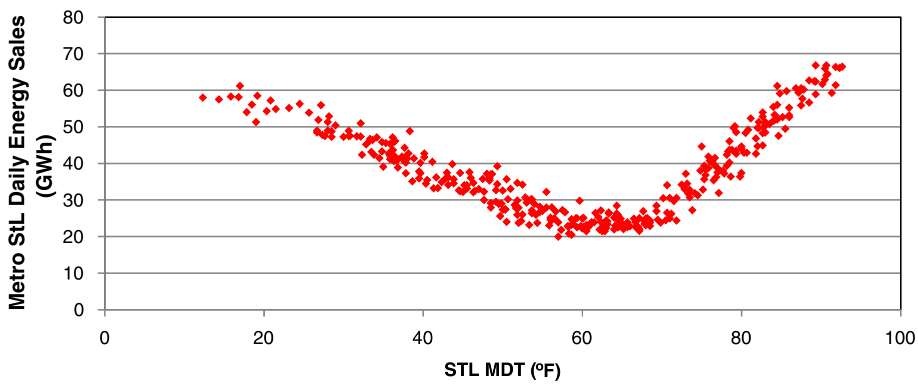


Fig. 3. Metropolitan St. Louis (Metro StL) 2011 daily residential electric energy sales and the corresponding STL MDT.

significant difference in the weather normalization adjustments to sales and revenues adjustments.

Section 2 introduces a weather normalization process for electric utility revenues. Section 3 discusses the computation and application of daily normal temperatures. Section 4 identifies the SCN biases and proposes alternative unbiased daily normal temperatures. In Section 5 SCN and alternative normal test year electric energy sales and revenues are simulated. Section 6 discusses implications of alternative daily normal temperatures for electric rate design.

2. Weather normalization

Energy sales for space heating and cooling are highly responsive to ambient temperature. The object of weather normalization is to find the level of energy sales consistent with the normal temperature pattern, assuming ceteris paribus. During the cooling season, as the temperature reaches higher levels, electricity sales increase as the demand for cooling such as air conditioning, ventilation, and refrigeration increases. During the heating season, as temperature falls the demand for additional space heating also results in increased energy sales.

A regulated energy utility is authorized to recover its fixed costs and variable costs as the result of a rate case or another regulatory process. The amount of revenue authorized is based on a specified rate-of-return and allowed expenses. The weather normalization of sales and revenues is a fundamental calculation in this regulatory process. An initial step in rate design is to determine the normal level of rate revenue and the quantification of associated variable costs.

Weather normalization uses load research data to determine the relationship between class specific sales and temperature variation. These relationships may include different base usage parameters for different days of the week and months of the year. For instance, for residential and commercial energy sales models, the variation in daily average temperature is the independent variable that determines the day-to-day variation in energy sales.

The relationship between daily residential electricity usage in the St. Louis metropolitan area (Metro StL) and the corresponding mean daily temperature (MDT) at Lambert — St. Louis International Airport (STL) in the test year 2011 is illustrated in Fig. 3. MDT is the simple average of the day's maximum daily temperature (Tmax) and minimum daily temperature (Tmin). The equation form of the daily mean temperature of dth day is as follows:

$$\mathrm{MDT}_d = \frac{1}{2}\,\mathrm{Tmax}_d + \frac{1}{2}\mathrm{Tmin}_d. \quad (1)$$

It is generally recognized that the response of electric energy sales to temperature is not uniformly linear as seen in Fig. 3 (Train et al., 1983). A rise in temperature 65 °F to 70 °F will not usually elicit the same response in electric energy sales as a rise from 80 °F to 85 °F, and a drop from 65 °F to 60 °F will not have the same effect as a drop from 50 °F to 45 °F.

In this study, we assume a test year is historical and a model of test year sales is developed from the relationship between energy sales and weather in the test year.[4] The model quantifies a change in energy sales during a specified time period, resulting from a change in the weather variable. The weather normalized sales adjustment is based on the difference between normal weather and actual weather during these periods in the test year.

A general model (Eq. (2)) characterizes the relationship between energy sales in a defined time period in the test year to weather and non-weather variables. The model parameters can be statistically estimated then the empirical model can be used to weather normalize energy sales:

$$E_t = F(w_t, x_t, \varepsilon_t) \quad (2)$$

where E is the amount of energy sales, w is a vector of weather variables that determine energy sales, x is a vector of non-weather variables that determine energy sales, ε is unexplained variation in energy sales, t is the time-period such as an hour, a day, a month, or billing cycle, and F is a function that relates the energy sales to the observed explanatory variables. This model is general and needs further specification for practical use in weather normalization.

If it is assumed that the energy response is invariant in the specified time period, and no interactivity among variables w,x, and ε, then the independent variables can be expressed as additively separable (Eq. (3)),

$$E_t = f(w_t) + g(x_t) + \varepsilon_t \quad (3)$$

where $E(t)$ is the amount of energy usage at time t,[5] w_t is a weather vector at time t, $f(.)$ is the amount of weather sensitive energy sales, x_t is a non-weather vector at time t, $g(.)$ is the amount of non-weather

[4] If a rate case adopts a forward test year, normal weather is used to forecast utility's future energy sales.

[5] Usually, weather normalization is conducted on daily level base. One reason is that the shortest time span available for climate normals is daily data. In some cases, the amount of energy usage is given for each billing month which is different from any given calendar month. Yet there are 21 different billing cycles so that eventually we need daily temperature normals. Therefore, average daily usage and average daily temperature for a given billing month are used for calculating weather normalization of energy consumption. In some cases, hourly load should be weather normalized. Because there is no official hourly climate normal data, daily peak load and daily average load are first normalized and then normalized hourly load shape is extrapolated from the daily normal loads. In summary, daily temperature normals are the fundamental units for most weather normalization calculations.

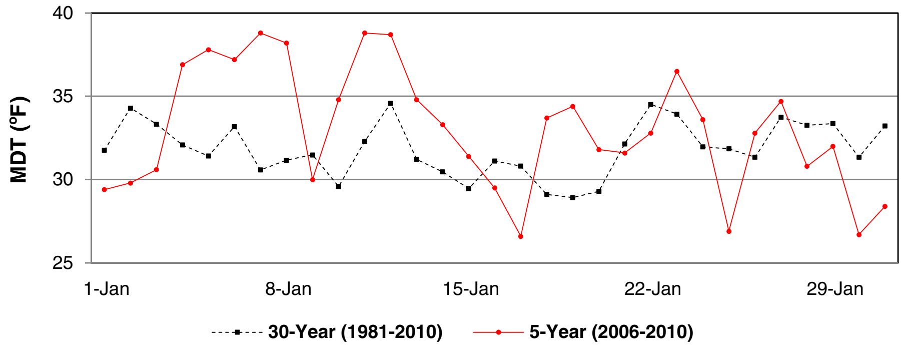


Fig. 4. STL 30-year and 5-year normal January MDT.

sensitive energy sales, and ε_t is the amount of the unexplained energy consumption at time t.

If we define the weather normal function, $N(w_t)$, as the normal weather value at time t of the observed weather value w_t then the normalized energy usage NE_t can be expressed as follows:

$$NE_t = f(N(w_t)) + g(x_t) + \varepsilon_t. \tag{4}$$

Therefore, the weather normalization adjustment $WNA(w_t)$ of energy usage at time t can be expressed as follows:

$$WNA(w_t) = f(N(w_t)) - f(w_t). \tag{5}$$

For instance, if at time t, we observe the actual energy usage, E_a, with the actual weather, w_a, then weather normalized energy usage, E_n, satisfies the following:

$$E_n = E_a + WNA(w_a). \tag{6}$$

Hence, the accuracy of the weather normal function, $N(w_t)$, is important, because bias in the normal weather function will result in a bias in the normalized energy usage estimate.

3. Climate normals

To define a precise weather normal function and estimate normalized energy usage, we need to have well defined climate normal calculations. The World Meteorological Organization (WMO) has defined climate normals as "period average computed for a uniform and relatively long period comprising at least three consecutive ten-year periods" and the SCN as "averages of climatological data computed for consecutive periods of 30 years (WMO, 2009)." The equation form of the SCN is as follows:

$$N^{30}(m, d; y_1) = \frac{1}{30}\sum_{y=y_1}^{y_1+29} O(y, m, d). \tag{7}$$

Here, $N^{30}(m,d;y_1)$ is the 30-year climate normal for a climate element of month, m, day, d, with normal period starting year, y_1, and $O(y,m,d)$ is the observed daily value for the climate element of year, y, month, m and day, d. This definition assumes that if the climate is not stationary any trend will be captured in the decadal update of the 30-year normal.

Technically, weather normalization is not forecasting. In load forecasting on the reliability of the 30-year normal has been broadly challenged recently (Livezey et al., 2007; Milly et al., 2008). A profusion

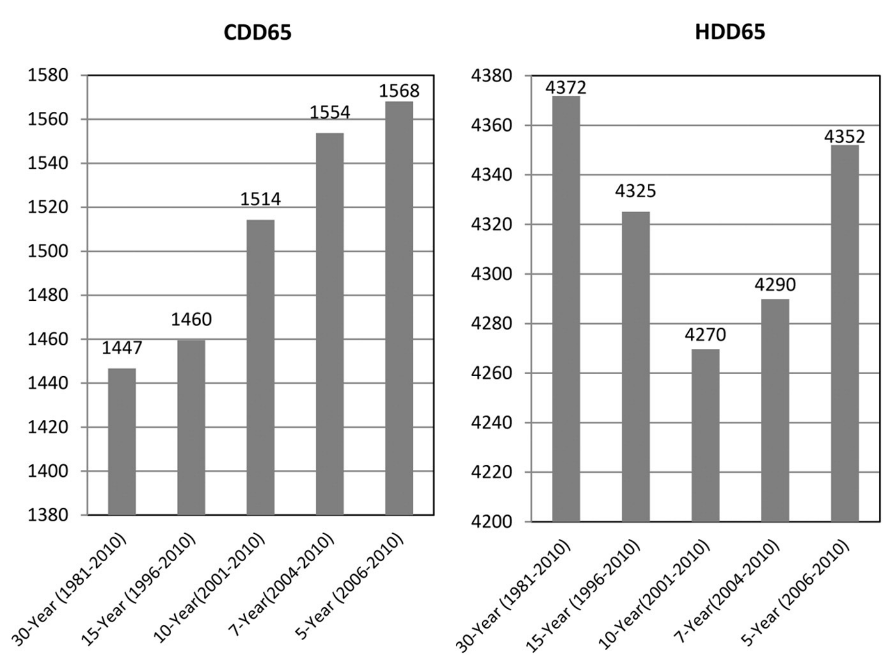


Fig. 5. STL annual CDD65 and HDD65 normals.

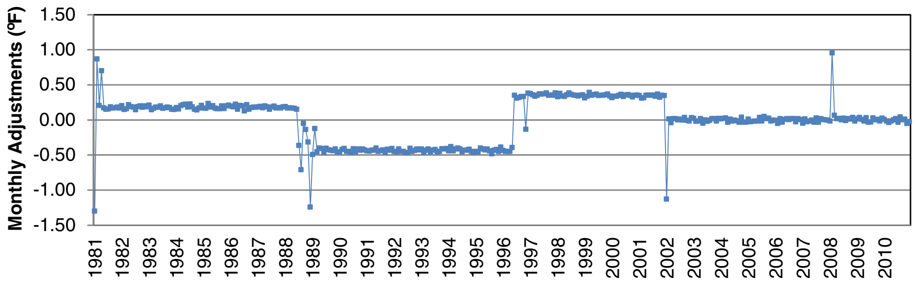


Fig. 6. Monthly adjustments to STL MDT (1981–2010). Note: Monthly adjustment = Homogenized monthly MDT of NOAA 1981–2010 normals − Observed monthly MDT.

of studies suggest that utilities and regulatory agencies in the U.S. energy industry are moving to shorter-term averages for forecasting (Arguez and Vose, 2011). Optimal Climate Normals, Least Squares Linear Trend Fits, and Hinge Fits are examples of alternative forecasting methodologies (Wilks, 2013). The appropriate methodology cannot be uniformly prescribed but needs to be evaluated in the context of the application and whether the application is normalization or forecasting.

The more general equation form of a climate normal is:

$$N^n(m,d;y_1) = \sum_{y=y_1}^{y_1+n-1} W(y)O(y,m,d). \tag{8}$$

Here, $N^n(m,d;y_1)$ is the n-year climate normal of month, m, day, d, with normal period starting year, y_1, $W(y)$ is a weight for year, y, and $O(y,m,d)$ is the observed daily value of year, y, month, m, and day, d. Using the STL temperature data set from January 1, 1981 to December 31, 2010, 30-year (1981–2010) and 5-year (2006–2010) normal MDTs for January were computed (Fig. 4). The 5-year normal January MDT has a larger day to day variation. The 5-year normal January MDT reflects recent weather trends and in some applications may be better for a short term forecasting (Angel et al., 1993), but it is not better in terms of characterizing the variation in ambient temperature over a longer period time.

In energy utility regulation, heating degree days with a base of 65 °F (HDD65) and cooling degree days with a base of 65 °F (CDD65) are conventionally used in revenue requirement calculation. HDD65 and CDD65 are calculated as the difference between the MDT and a chosen base 65 °F.[6] HDD65 is calculated as the difference between 65 °F and the MDT when the MDT is below 65 °F, and is equal to zero when the MDT is above 65 °F: HDD65 for day d is defined as

$$\text{HDD65} = \mathbf{max}[0,(65-T_d)], \tag{9}$$

where T_d is the MDT for day, d. Similarly, CDD65 is calculated as the difference between 65 °F and the MDT when the MDT is above 65 °F, and is equal to zero when the MDT is below 65 °F. CDD65 for day d is defined as.

$$\text{CDD65} = \mathbf{max}[0,(T_d-65)]. \tag{10}$$

Because of weather cycles, the normal for HDD65 and CDD65 will vary according to the length of time period (Fig. 5).

After determining that weather normalization is the appropriate methodology the next question to be confronted is which climate normal period is the better for weather normalization. The goal of the Missouri Public Service Commission (MPSC) is to balance the interests of ratepayers and company stockholders. There are often competing economic interests in choosing the normal time period for weather normalizing energy sales and revenues. These competing stakeholder interests may result in protracted administrative proceedings involving countervailing testimony resulting in added time and costs to the regulatory process. Since the 1990's the position of the MPSC Staff has been that the WMO and the NOAA 30-year normal is the most practical and authoritative due to the effort of NOAA to provide a 30-year weather station time series for the normal calculation that includes adjustments for any changes in the station location and/or instrumentation.

4. Biases and mitigation procedure

4.1. Homogenization

Even if the 30-year climate normal period is accepted by all regulatory stakeholders there are often problems with the time series of weather observations that lead to disagreements about how to identify biases in and calculate adjustments to the time series. For instance, if the weather instruments were relocated, replaced, or recalibrated, the observed weather data series may be inconsistent and biased. Changes in observation procedures or in an instrument's environment may also occur during the normal period. Any inhomogeneity in the climate data series needs to be identified and quantified to achieve a reliable adjustment to weather observation time series.

In the calculation of the 1981–2010 climate normals, NOAA developed an automated homogenization algorithm based on the pairwise comparison of monthly temperature series from nearby weather stations. As described in Menne and Williams (2009), the National Climatic Data Center (NCDC) developed a robust quality control and standardization methodology which yielded consistent monthly maximum and minimum temperature time series for each weather station (Arguez et al., 2012). The monthly homogenization algorithm for the temperature observations was applied to the daily maximum and minimum temperature observations (Vincent et al., 2002).

Usually the 30-year time series has been statistically evaluated and adjusted for consistency. These statistical techniques identify and adjust for missing data values and discontinuities. The discontinuities may include documented and undocumented changes in instruments, location, elevation, observation schedule, and site characteristics. The equation form of climate normal that includes adjustments in the observed daily data series is:

$$N_A^{30}(m,d;y_1) = \frac{1}{30}\sum_{y=y_1}^{y_1+29} A(y,m,d). \tag{11}$$

$N_A^{30}(m,d;y_1)$ is the 30-year climate normal of month, m, day, d, with normal period starting year y_1, and $A(y,m,d)$ is the adjusted observed daily value of year, y, month, m, and day, d.[7]

The STL 1981-2010 time series has adjustments for documented and undocumented changes in the MDT observations as a result of the

[6] For the consistency, degree day values are calculated by the definition of degree day using the associated average of MDT for the given calendar date.

[7] The homogenization of historic data is conducted using monthly data series. For calculating daily adjustments, please see Vincent et al. (2002).

Table 1
STL Meta Data (NOAA Multi-Network Metadata System).

Begin date	End date	Latitude	Longitude	Elevation	Equipment
1/18/2002	3/31/2012	38.752500 (38°45′09″N)	−90.373610 (90°22′24″W)	GROUND: 531 FEET	ASOS HYGROTHERMOMETER
6/1/1996	1/18/2002	38.752500 (38°45′09″N)	−90.373610 (90°22′24″W)	GROUND: 568 FEET	ASOS HYGROTHERMOMETER
7/1/1995	6/1/1996	38.750000 (38°45′00″N)	−90.366670 (90°22′00″W)	AIRPORT: 618 FEET	MAX-MIN THERMOMETERS
7/11/1988	7/1/1995	38.750000 (38°45′00″N)	−90.366670 (90°22′00″W)	GROUND: 535 FEET	MAX-MIN THERMOMETERS
1/1/1980	7/11/1988	38.750000 (38°45′00″N)	−90.366670 (90°22′00″W)	GROUND: 535 FEET	UNKNOWN - TEMP

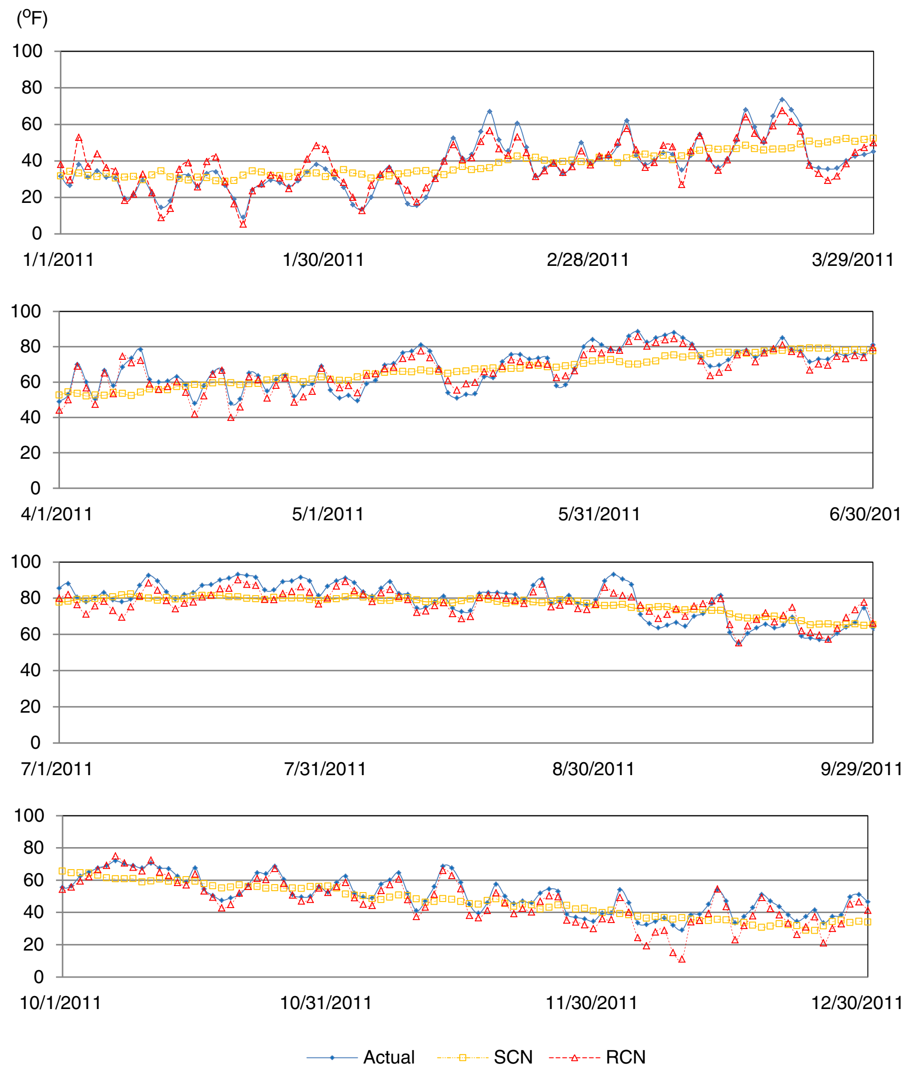


Fig. 7. STL 2011 MDT, SCN, and RCN.

NOAA's homogenization (Fig. 6). Adjustments indicate difference between the NOAA's monthly homogenized temperature and the monthly average of observed temperature, January 1, 1981 to December 31, 2010, at the STL.

Documented changes during the normal period are reported in Multi-Network Meta Data System of the NOAA.

System of the NOAA.[8]

The changes in instruments and locations documented in Table 1 are reflected in the time series (Fig. 6). There are significant adjustments in 1988, 1996, and 2002.

[8] See http://www.ncdc.noaa.gov/homr/.

4.2. Preserving variation

The goal of electric power system load research is to accurately characterize daily peak load and daily average load, which are very temperature dependent. To properly determine the temperature normalized daily peak load, daily temperature variation should be consistent with the variation in the daily climate normal time series. As explained in introduction, this variation is lost in the SCN which is calculated using the typical averaging process which eliminates extremes in the time series of observations. If the SCN set of MDT is used in a load research model, the result is a set of normalized daily peak loads in which the daily variation is suppressed. Thus, the monthly and annual series of SCN daily temperature series have a bias in their variation which results in a

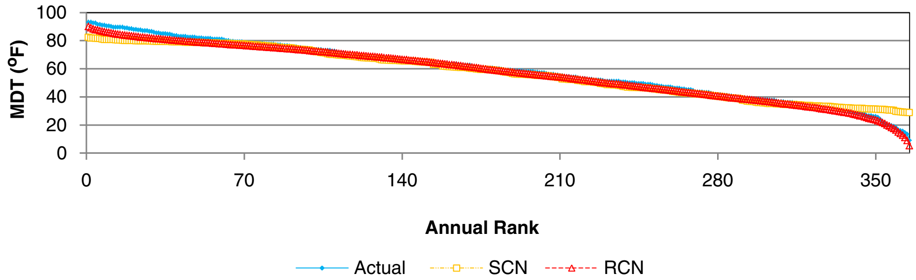


Fig. 8. STL Ranked 2011 MDT, SCN, and RCN.

bias in the variation of any monthly or annual time series estimates of daily peak load. Subsequently in any related analysis of the potential variation in generation, transmission, or distribution is suppressed.

The daily temperature pattern in months and years should be reflected in the normalized test year daily temperature time series used for the weather normalization of energy sales, there is a non-linearity in the response of energy sales to MDT. So, the normalized daily energy sales need to reflect the test year daily temperature variation. More importantly, because of the non-linear relationship between temperature and energy sales (Fig. 3), removing variation in daily temperatures could lead to a significant error in the weather normalization adjustment to test year sales. Therefore, the set of daily normal temperatures in a month should approximate the range of observed daily temperatures in a set of monthly and annual MDT.

To capture the historic MDT pattern for each test year month and filter any anomalies, the staff of MPSC developed a computational procedure based on the Monthly Climate Rank (MCR) of the test year observed MDT. The MCR is an intermediate calculation used in the compilation of the final Ranked Climatological Normal (RCN) series. It is used for assigning yearly ranked temperature values from the 30-year time series to the corresponding test year date which has the same monthly temperature rank.

A more general equation form for a temperature in the MCR series is:

$$N_{MR}^{30}(m,d;y_1) = \frac{1}{30}\sum_{y=y_1}^{y_1+29} A_{MR}(y,m,d). \tag{12}$$

$N_{MR}^{30}(m,d;y_1)$ is a ranked temperature for a day in the MRC series i.e. the dth highest daily temperature in month, m, in the MCR series for the 30-year climate normal period starting year, y_1, and $A_{MR}(y,m,d)$ is dth highest daily temperature of the adjusted daily temperature in month, m, year, y. The MCR series preserves the normalized daily temperature pattern each month of the test year.

The normal daily temperatures need to properly reflect the variation of the test year daily temperatures. The RCN series is based upon a 30-year average of the ranked daily temperature in each year assigned to the corresponding the monthly ranked test year temperature using the MCR. The equation form of a normal MDT in the RCN series is calculated using the monthly and yearly rank:

$$N^{30}(m,d;y_1,y_T) = \frac{1}{30}\sum_{y=y_1}^{y_1+29} A_{YR}(y,m,D). \tag{13}$$

Here, a rank in the RCN, $N^{30}(m,d;y_1,y_T)$, is the 30-year daily normal of month, m, day,d, normal period starting year, y_1, assuming the temperature of month, m, day, d, in the test year, y_T, has Dth monthly rank. $A_{YR}(y,m,D)$ is a temperature value which yearly rank in temperature data series of year, y, is the same as the yearly rank of the temperature value, $N_{MR}^{30}(m,D;y_1)$, in the MCR, $\{N_{MR}^{30}(.,.;y_1)\}$.

The main reason the monthly rank is employed in this procedure is that weather normalized consumer usage will be used in calculating monthly revenues and monthly expenses related to monthly characteristics of the test year. If we just use yearly rank then the daily normal pattern of temperature variation in a month will reflect an abnormal temperature variation in a month in the test year. Therefore, the RCN methodology not only preserves both monthly and annual temperature variation but also minimizes the difference between test year daily temperatures and normal daily temperatures (Turner and Lissik, 1991).

The daily RCN, which is calculated by the rank and average method explained above and the daily SCN are compared in Fig. 7. The variation in the daily RCN reflects the variation in the test year daily temperature observations whereas the daily SCN variations in temperature values are dampened.

Comparison of yearly ranked daily test year, RCN and SCN temperature series are graphed in Fig. 8. At the upper end and lower end of the plot it can be seen that both hot and cold extreme temperatures are dampened in the SCN data series, but are reflected in the RCN data series. The RCN has a relatively similar shape compared to the test year daily temperature series in both the higher and lower ranked temperature values.

For each year of the normal period (1981–2010) the average of the upper 95th percentile (warmest 18 days) MDT is plotted in Fig. 9. Similarly the average of lower 5th percentile (coldest 18 days) MDT for each year are plotted in Fig. 10. The corresponding average of the

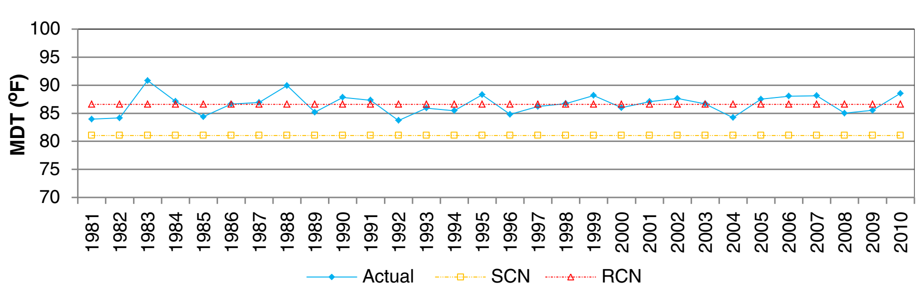


Fig. 9. STL 95th percentile (18th warmest) MDT — actual, SCN, and RCN.

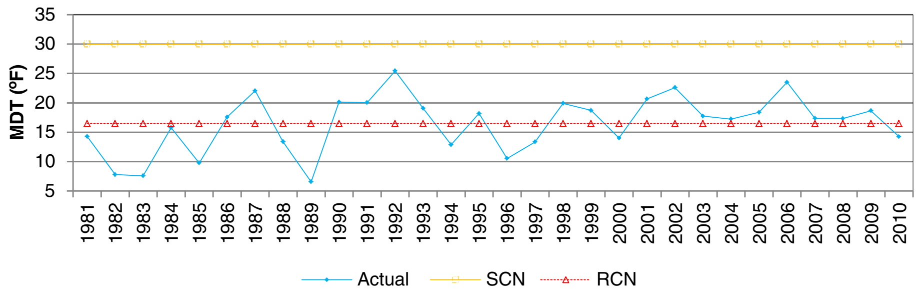


Fig. 10. STL 5th percentile (18th coldest) MDT — actual, SCN, and RCN.

highest 18 days of the SCN and RCN are plotted in Fig. 9 each year, and the average of the lowest 18 days of the SCN and the RCN are plotted each year in Fig. 10. In both figures it can be seen that the average SCN is offset from the lower 5th percentile average and upper 95th percentile average of the years in the period, 1981–2010, whereas the RCN, by design, goes through the average of the lower 5th percentile and upper 95th percentile respectively.

The histograms of the distribution of Actual MDT for the normal period (1981–2010), the distribution of the SCN, and the distribution of the RCN are plotted in Fig. 11. The distribution of the RCN MDT has a better fit to the distribution of MDT of 30-year period from 1981 to 2010 than the distribution of the SCN MDT. In Fig. 11, the distribution of the RCN MDT is almost the same as the distribution of the Actual MDT from 1981 to 2010. The distribution of the SCN MDT shows that extremes lower than 20 °F and higher than 90 °F are removed. The SCN distribution also shows abnormally high density in the intervals from 30 °F to 40 °F and 70 °F to 80 °F. In Fig. 12, it can be seen that cumulative distribution function of RCN and the 30-year MDT series are almost coincidental while the SCN series deviates in the lower temperatures (25 °F–35 °F) and the higher temperatures (75 °F–85 °F).

4.3. The cumulative effect

A persistent weather pattern (such as a “heat wave” or a “cold air mass”) has a cumulative effect on daily energy use for space cooling and heating. Thus, in summer, a warm day after one or more warm days has greater total daily energy sales than the same warm day preceded by cool or temperate days. For example, during the cooling season, even if the MDT is the same for two Wednesdays in different weeks, more air conditioning would be used on the Wednesday with the warmer preceding Tuesday. Assuming a positive linear load and sales response of a weather observation, such as temperature in the summer, the cumulative effect of weather can be measured by a regression model,

$$\text{Energy Sales} = \beta_0 + \beta_1 W_t + \beta_2 W_{t-1} + \gamma \text{NW}_t + \varepsilon_t \tag{14}$$

where W_t is a weather observation on day t, W_{t-1} is the weather observation on the previous day, NW_t is a non-weather variable, ε_t is an error. Both $\beta_1$and β_2 are anticipated to be positive. In the weather normalization process, a regression model with weather lag variable is problematic because the relationships between two days in a test year and in climate normal are different.

Another way to internalize the cumulative temperature effect is to calculate a two-day weighted mean daily temperature (TWMDT) series for the test year. The equation form of TWMDT for day d is:

$$\text{TWMDT}_d = \alpha_1 \text{MDT}_{d-1} + \alpha_1 \text{MDT}_d \tag{15}$$

where

$$\alpha_1 = \frac{\beta_1}{\beta_1 + \beta_2} \text{and } \alpha_2 = \frac{\beta_2}{\beta_1 + \beta_2}.$$

Based on empirical analysis of weighting alternatives a set of TWMDT is calculated using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight ($\beta_1 = 1$ and $\beta_2 = 2$). The model using the TWMDT series shows a higher explanatory power than regression model using the MDT series. In other words, when the other independent variables are the same, the regression model of daily electric energy sales with the TWMDT series shows a higher R-square than the model with the MDT series. For instance, as demonstrated by the regression model in the next section, adjusted R-square is 0.9643 in the regression with the TWMDT series but the same regression model with

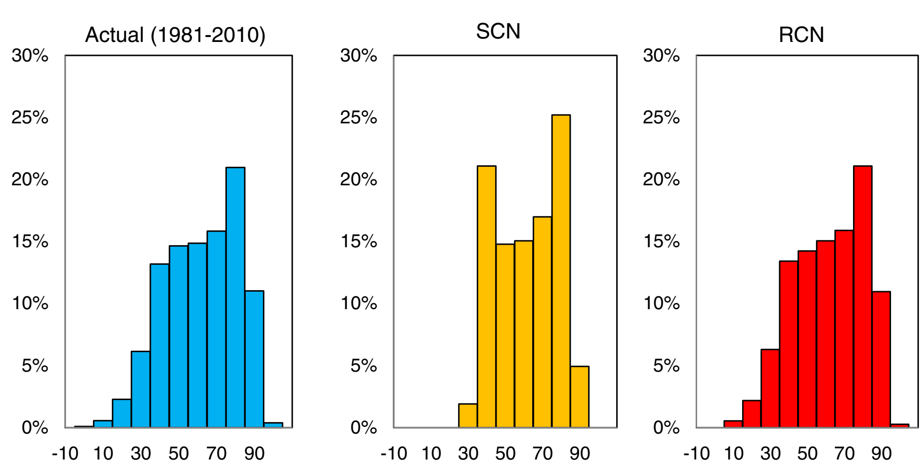


Fig. 11. STL density distributions of 1981–2010 MDT, SCN, and RCN.

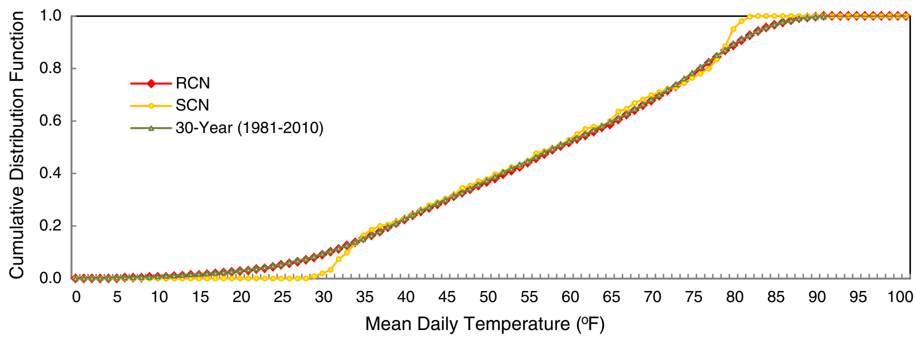


Fig. 12. Cumulative distribution functions of the daily temperature RCN and SCN series and the 30-year (1981–2010) MDT series.

the MDT series has an adjusted R-square of 0.9545. It is also demonstrated that for weather normalization the ranked normal TWMDT is more appropriate than the two day weighted mean of ranked normal MDT. The TWMDT accounts for the some of the cumulative effects of persistent temperatures on energy sales, but further investigation of the cumulative effect on sales needs to be conducted.

4.4. Mitigation of other anomalies

Further refinement of the daily energy sales model must be made for weekends and holidays (non-workdays), when energy sales responses to TWMDT are significantly different due to variations in economic activity. Therefore, if the monthly extreme temperature occurs on a non-workday in the test year, the relationship between test year weather and energy sales will diverge. Consequently, test year days with temperature extremes are reassigned to a workdays with a similar TWMDT rank.

In test years that are non-leap years the observations on February 29 in the thirty year period are excluded from the normal series of MDT in the calculation of the daily climate normal. If the test year is a leap year, the observations on February 29 are included in the normal series, and the non-leap years in the normal series is augmented using the average of February 28 and March 1, to generate a value for February 29 to complete the 30 year period to calculate the daily climate normal.

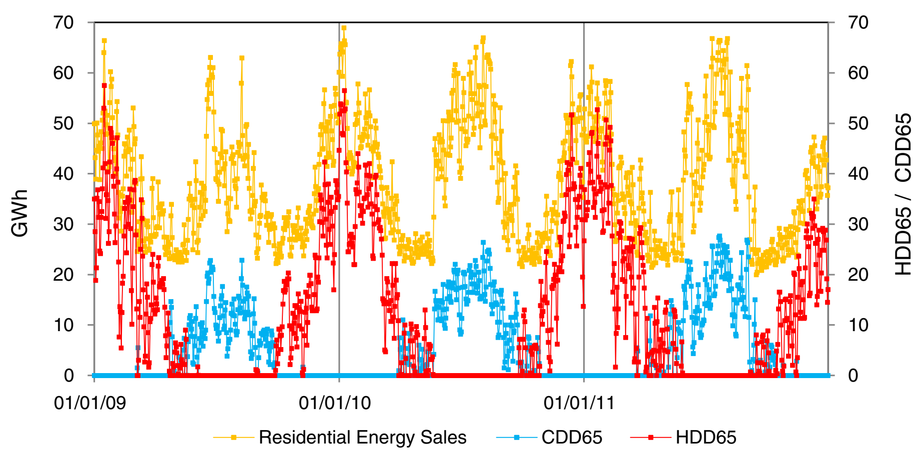


Fig. 13. Metro StL Daily Residential Energy (GWh) sales and STL HDD65 and CDD65 (2009–2011).

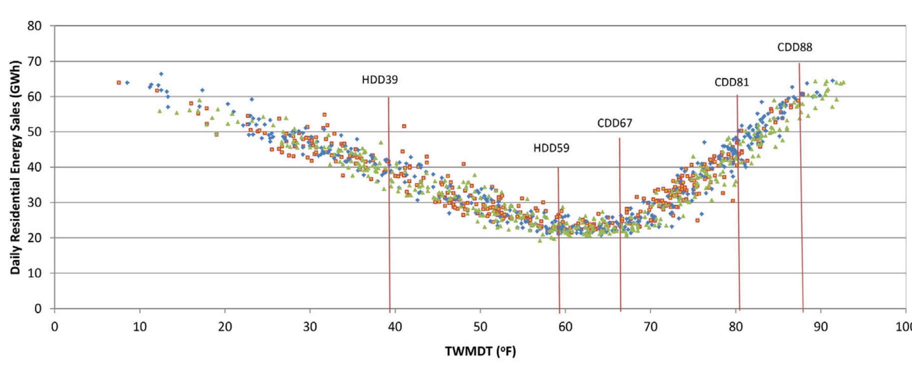


Fig. 14. Piecewise linear inflection points for Metro StL daily residential electric energy sales vs. STL TWMDT used to calculate HDD and CDD.

Table 2
Descriptive statistics for using TWMDT.

Variable	Count	Mean	StdDev	Min	Max	Skewness	Kurtosis	Jarque–Bera	Probability	CorrYX
RESENERGY (GWh)	1095	38,115	11,783	19,978	68,900	0.454	2.195	67	0.000	1.000
HDD39	1095	2.039	5.095	0.000	31.487	2.962	12.028	5319	0.000	0.507
HDD59	1095	8.812	12.264	0.000	51.487	1.247	3.448	293	0.000	0.454
CDD67	1095	4.083	6.470	0.000	25.667	1.420	3.796	397	0.000	0.555
CDD81	1095	0.494	1.698	0.000	11.667	4.009	19.540	15415	0.000	0.527
CDD88	1095	0.047	0.366	0.000	4.667	8.925	88.300	346507	0.000	0.282
EMPLOYMENT (1000)	1095	2517	35	2449	2568	−0.548	2.500	66	0.000	−0.093
PRICE ($/KWh)	1095	0.082	0.018	0.053	0.121	0.306	2.046	59	0.000	0.114

Table 3
Regression Statistics for TWMDT and MDT Models.

	[1] TWMDT	[2] MDT
Adjusted R Squared	0.9643	0.9039
Standard Error	2240	3672
Variable	Coefficient	Coefficient
HDD39	147**	−749**
HDD59	615**	811**
CDD67	1,372**	1,206**
CDD81	844**	765**
CDD88	−1,230**	−834*
EMPLOYMENT	−23**	−31**
PRICE	−90,431**	−102,435**
DJANUARY	−2,323**	1,127
DFEBRUARY	−3,473**	−3,297**
DMARCH	−5,539**	−8,993**
DAPRIL	−6,348**	−9,328**
DMAY	−4,005**	−6,405**
DJUNE	769	−217
DJULY	1,785	1,042
DAUGUST	420	−605
DSEPTEMBER	−5,299**	−7,593**
DOCTOBER	−6,951**	−10,062**
DNOVEMBER	−5,307**	−8,928**
DSUNDAY	1,100**	1,317**
DMONDAY	−873*	−565
DTUESDAY	−1,438**	−855*
DWEDNESDAY	−1,668**	−1,050*
DTHURSDAY	−1,460**	−826*
DFRIDAY	−1,415**	−1,088*
Intercept	96,192**	134,332**

* $P < 0.1$.
** $P < 0.01$.

5. Economic impact

A simulation of electric rate case weather normalized revenue estimates can demonstrate the difference in the economic impact of the SCN and RCN adjustments to daily test year weather. For comparison, the adjustments to normal weather are calculated using both the SCN series and RCN series to determine the revenue difference between the two methods. The statistical relationship between weather and energy sales can be characterized in the regression model:

$$\text{Energy Sales} = \beta_0 + \boldsymbol{\beta}\cdot\boldsymbol{W} + \boldsymbol{\gamma}\cdot\boldsymbol{NW} + \varepsilon, \tag{16}$$

where **W** is a vector of weather variables and **NW** is a vector of non-weather variables.

In the simulation, RESENERGY (GWh), the series of Ameren Missouri daily residential sales are Energy Sales. The STL daily MDTs for the test year are from the Midwest Regional Climate Center (MRCC).[9] The serially complete monthly temperature data series from NOAA[10] are used to compute normal weather, Ameren Missouri daily residential electric energy sales, the daily HDD65 and CDD65, derived from the TWMDT for 2009–2011 are overlaid in Fig. 13.

The quantitative relationship between daily temperature and daily residential electric energy sales varies according to the daily temperature range because electricity is used for heating and cooling. Consequently, the weather variables, HDD and CDD, are calculated with bases other than the standard base of 65 °F that are adjusted to the daily temperature range using MDT and TWMDT. HDD with an adjusted base of *THB* for day *d* are calculated as follows:

$$HDD_d THB = \mathbf{max}[0, (THB - T_d)] \tag{17}$$

where T_d is one of the daily temperature calculations for day *d* (i.e. MDT or TWMDT). Similarly, CDD with the base of *TCB* for day *d* are calculated as follows:

$$CDD_d TCB = \mathbf{max}[0, (T_d - TCB)]. \tag{18}$$

Bases were determined by analyzing the relationship between daily energy sales and the daily temperatures. Because of the piecewise linearity of daily energy sales to daily temperature, five bases are used for generating the degree day variables, HDD39, HDD59, CDD67, CDD81, and CDD88. The daily energy sales series, RESENERGY corresponding to the TWMDT series with the five degree day break points are plotted in Fig. 14.

The non-weather factors of season, electricity price and local economic activity are also included. Discrete variables for weeks and months are employed, allowing each time unit a coefficient reflecting factors that are outside the model. The variable, DSUNDAY, is one when the day is Sunday and zero otherwise. Holidays are excluded from the regression because each holiday has a unique characteristic for electric energy sales.

PRICE, P_m, is the average price per kWh paid by residential customers in a month.[11] P_m is calculated from the Ameren Missouri residential class revenue, R_m, per kWh sales, S_m,reported by the U. S. Energy Information Administration,

$$P_m = \frac{R_m}{S_m} - (m =, \ldots, 12). \tag{19}$$

PRICE, P_m, changes monthly for several reasons. First, during the period regulated rate changes occurred in March 1, 2009; June 21, 2010; and July 31, 2011. Second, average rates change as usage changes due to rate designs such as declining block rates and seasonal rates (e.g.

9 See http://mrcc.isws.illinois.edu/CLIMATE/.

10 See ftp://ftp.ncdc.noaa.gov/pub/data/normals/1981-2010/source-datasets/.

11 Ameren Missouri's residential service class rates are not linear. However, evidence from recent studies suggests that electricity consumers respond to average price rather than marginal price or expected marginal price. Customers do not understand complex rate structures (Ito, 2012). Ameren Missouri has an Optional Time-of-Day residential rate, but less than 0.001% of residential customers have requested this rate. The monthly price of electricity used in this study is the monthly average normalized price compiled by the Bureau of Labor Statistics in the quarterly CPI of Metro StL.

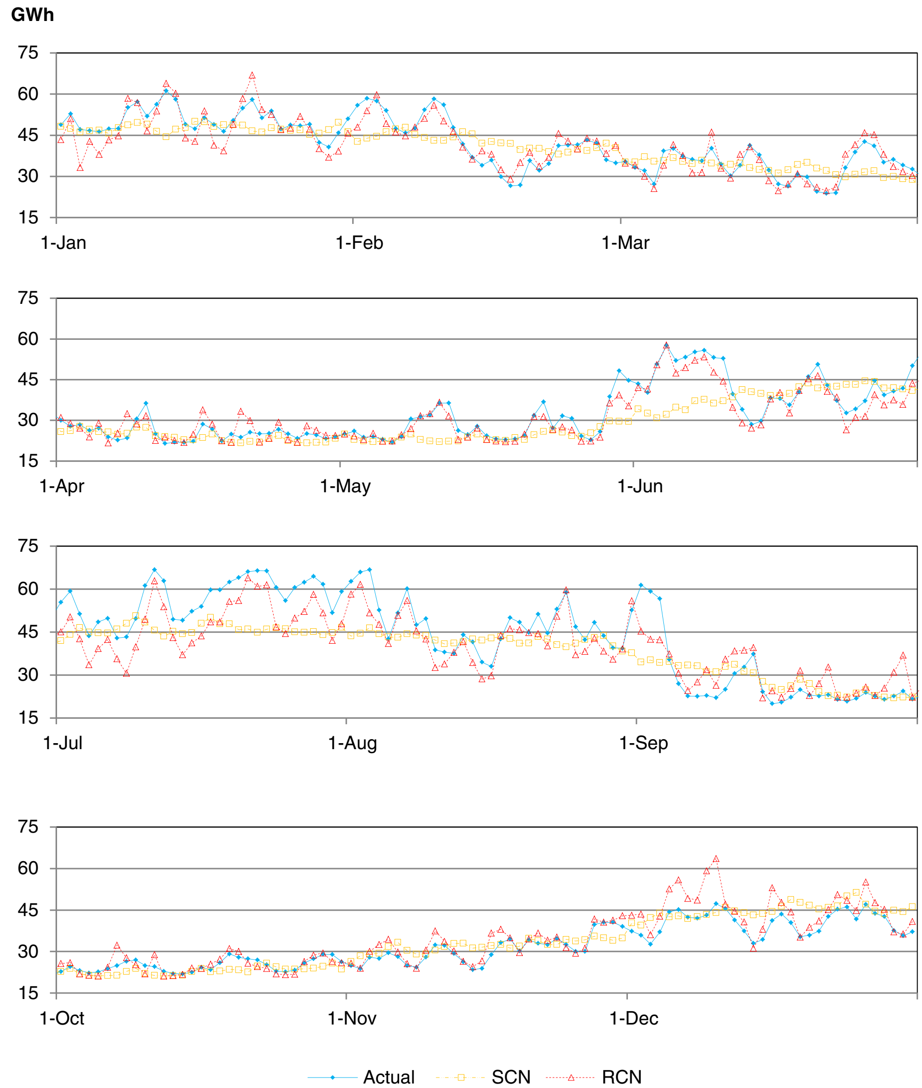


Fig. 15. Metro StL 2011 daily residential electric energy sales and the daily SCN and RCN weather normalized residential electric energy sales.

Table 4
Metro StL energy sales and TWMDT adjustments using SCN and RCN.

	Actual		SCN Adjustment		RCN Adjustment		Difference	
2011	Usage*	Revenue**	Usage*	Revenue**	Usage*	Revenue**	Usage*	Revenue**
Jan	1,661,987	109,132	(85,303)	(5,175)	(117,476)	(7,127)	(32,173)	(1,952)
Feb	1,434,501	96,953	(86,758)	(5,361)	(81,885)	(5,060)	4,872	301
Mar	1,122,266	80,377	32,566	2,092	(36,735)	(2,359)	(69,301)	(4,451)
Apr	929,098	70,102	(27,892)	(1,856)	6,432	428	34,325	2,284
May	798,299	63,141	(79,947)	(5,495)	17,064	1,173	97,011	6,667
Jun	1,071,000	122,441	(212,035)	(22,603)	(8,075)	(861)	203,960	21,742
Jul	1,411,405	158,725	(112,947)	(12,040)	(143,011)	(15,245)	(30,064)	(3,205)
Aug	1,668,829	186,176	(319,234)	(34,030)	(208,639)	(22,241)	110,595	11,789
Sep	1,301,542	147,016	(119,661)	(12,756)	(169,949)	(18,117)	(50,288)	(5,361)
Oct	779,537	62,063	(20,786)	(1,435)	(56,509)	(3,901)	(35,724)	(2,466)
Nov	777,438	61,744	4,752	327	43,486	2,992	38,734	2,665
Dec	1,099,427	79,421	57,440	3,717	42,802	2,770	(14,638)	(947)
Total	14,055,329	1,237,291	(969,804)	(94,615)	(712,494)	(67,548)	257,309	27,067

Note: Values with red numbers in the parenthesis are negative.
* MWh.
** $1000.

higher rate in summer compared to winter). Third, two components of price, the fuel adjustment clause and purchase power adjustment charge were updated triennially as allowed by regulations.

EMPLOYMENT, quarterly employment in Metro StL from the Bureau of Labor Statistics is used as a proxy for local economic conditions. Interestingly, previous research has found that residential energy sales are negatively correlated with employment (Train et al., 1983). One explanation of this may be that as employment increases fewer people are at home during the work day. The major variables are in Table 2 and the regression results are in Table 3.

In Fig. 15 contains the daily electric energy sales for the test year 2011, along with the weather normalized daily SCN and RCN electric energy sales. The daily RCN electric energy sales tracks seasonal usage patterns of actual sales more closely than the daily SCN electric energy sales. Both magnitude of sales and the seasonal variation of sales are reflected by the RCN electric energy sales. The results of the weather normalization adjustments of monthly electric energy sales and revenues using the SCN and the RCN are presented in Table 4.

The revenue adjustment to 2011 using the SCN, RA_S, is not the same as the revenue adjustment using the RCN, RA_R. Also some monthly adjustments are in different directions, the RA_S is negative and RA_R is positive. Some monthly difference in normalized electric energy sales and revenue for 2011 the SCN and the RCN is more than 17%.

6. Conclusion

This paper investigates the biases in the weather normalization adjustment to test year electric energy sales and revenues using the SCN. The RCN is introduced to provide a more accurate set of normal MDT by preserving MDT variation, and TWMDT is introduced to account for the cumulative temperature effects on energy sales. These weather variables avoid the bias in the weather normalization adjustment that can be introduced when the SCN and MDT are used.

For comparison, adjustments were calculated for 2011 Ameren Missouri daily residential electricity sales. The results reveal that the weather normalization adjustment is significantly improved using the RCN and TWMDT compared to the result using the SCN and MDT. The model using TWMDT has a higher adjusted R-square than the model using MDT (Table 3). The RCN fits the actual 30-year daily temperature distribution better than the SCN (Fig. 12). When the RCN, based on the NOAA-adjusted 30-year set of temperature observations, is used to compute the TWMDT the result is a less biased weather normalization adjustment of daily energy sales and revenue than the MDT from the SCN (Table 4).

Our review of the literature on weather normalization processes indicates that the SCN is the more frequently used climate normal. It has been demonstrated that a naive implementation of the SCN in certain applications such as daily load research, may cause significant biases in the analysis of daily load variation. Even if the mean of the SCN is not biased, the SCN variance is damped, so weather normalization adjustments can be biased. The main reason for this bias is that daily electric sales do not have a uniform response to weather. This non-linear response to weather requires characteristics in a climate normal to be used for energy utility weather normalization that the SCN doesn't have.

The relationship between energy sales and temperature is the most important factor in weather normalization. The daily residential electric sales response to temperature is nonlinear, so if a climate normal does not preserve extremes in daily temperature variation, the weather normalization adjustment will have a bias. Therefore, a daily climate normal for utility regulation should preserve the yearly and monthly weather pattern which corresponds to the test year weather variation. In addition to setting appropriate rates, accurately weather normalized energy sales are also required for evaluating the effectiveness of energy conservation and demand-side management programs. Furthermore, the more realistic climate normal will improve our understanding of energy market asset price dynamics (Mu, 2007).

Acknowledgement

The authors would like to thank to utility rate case participants including current and former commissioners and staff of MPSC, especially Shawn Lange.

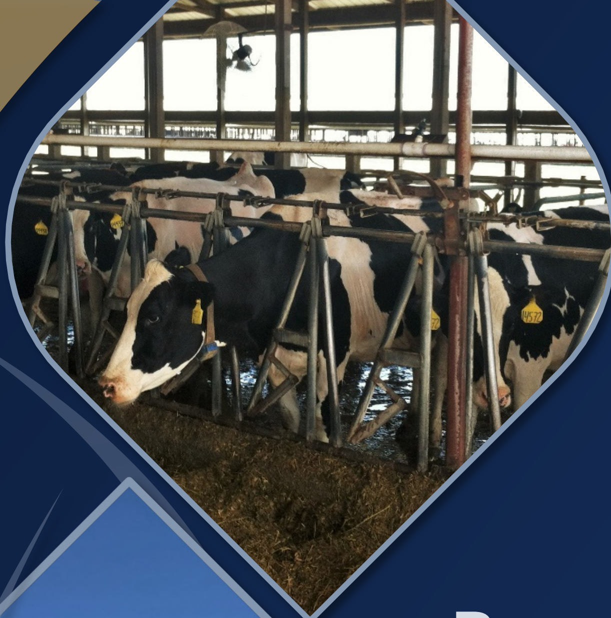
Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2015.12.016.

References

Angel, J.R., Easterling, W.R., Kirtsch, S.W., 1993. Towards defining appropriate averaging periods for climate normals. Climatol. Bull. 27, 29–44.
Arguez, A., Vose, R.S., 2011. The definition of the standard WMO climate normal: the key to deriving alternative climate normals. Bull. Am. Meteorol. Soc. 92 (6), 699–704.
Arguez, A., Durre, I., Applequist, S., Vose, R.S., Squires, M.F., Yin, X., Owen, T.W., 2012. NOAA's 1981–2010 US climate normals: an overview. Bull. Am. Meteorol. Soc. 93 (11), 1687–1697.
Arguez, A., Vose, R.S., Dissen, J., 2013. Alternative climate normals: impacts to the energy industry. Bull. Am. Meteorol. Soc. 94 (6), 975–976.
Bower, R.S., Bower, N.L., 1985. Weather normalization and natural gas regulation. Energy J. 6 (2), 101–115.
Croucher, M., 2011. Are energy efficiency standards within the electricity sector a form of regulatory capture? Energ Policy 39 (6), 3602–3604.
Dergiades, T., Tsoulfidis, L., 2008. Estimating residential demand for electricity in the United States, 1965–2006. Energy Econ. 30 (5), 2722–2730.
Elkhafif, M.A., 1996. An iterative approach for weather-correcting energy consumption data. Energy Econ. 18 (3), 221–230.
Finkelstein, J.M., Schafer, R.E., 1971. Improved goodness-of-fit tests. Biometrika 58 (3), 641–645.
Ito, K., 2012. Do consumers respond to marginal or average price? Evidence from nonlinear electricity pricing. Am. Econ. Rev. 104 (2), 537–563.
Livezey, R.E., Vinnikov, K.Y., Timofeyeva, M.M., Tinker, R., van den Dool, H.M., 2007. Estimation and extrapolation of climate normals and climatic trends. J. Appl. Meteorol. Climatol. 46 (11), 1759–1776.
Livezey, R.E., Hanser, P.Q., 2013. Redefining Normal Temperature. Public Utilities Fortnightly, pp. 28–34 May 2013.
Menne, M.J., Williams Jr., C.N., 2009. Homogenization of temperature series via pairwise comparisons. J. Clim. 22 (7), 1700–1717.
Milly, P.C.D., Betancourt, J., Falkenmark, M., Hirsch, R.M., Kundzewicz, Z.W., Lettenmaier, D.P., Stouffer, R.J., 2008. Stationarity is dead: whither water management? Science 319, 573–874.
Monts, K., Blissett, M., Wilson, R., 1989. Weather normalization of electricity sales to the school sector: potential model misspecification. Energy Econ. 11 (2), 127–132.
Mu, X., 2007. Weather, storage, and natural gas price dynamics: fundamentals and volatility. Energy Econ. 29 (1), 46–63.
Train, K., Ignelzi, P., Engle, R., Granger, C., Ramanathan, R., & Rice, J. (1983). Weather normalization of electricity sales. Final report (No. EPRI-EA-3143). Cambridge Systematics, Inc., Berkeley, CA (USA); Quantitative Economic Research, Inc., San Diego, CA (USA).
Turner, M., Lissik, E., 1991. Weather Normalization of Electric Loads, Demonstration: Calculation of Weather Normals. Internal Report of Research and Planning Department. Missouri Public Service Commission, Jefferson City, MO (USA).
US Census Bureau, 2012. Statistical Abstract of the United States. Economics and Statistics Administration, Department of Commerce, Washington, DC (USA).
Vincent, L.A., Zhang, X., Bonsal, B.R., Hogg, W.D., 2002. Homogenization of daily temperatures over Canada. J. Clim. 15 (11), 1322–1334.
Wilks, D.S., 2013. Projecting "normals" in a Non-stationary climate. J. Appl. Meteorol. Climatol. 52 (2), 289–302.
WMO, 2009. Hand book on Climate and Climate Temp Reporting. WMO/TD-No.1188. World Meteorological Organization, Geneva, Switzerland.

EPA 456-R-21-001



An Overview of Renewable Natural Gas from Biogas

January 2021

NaturalGas EPA POLLUTION PREVENTER

AgSTAR

LANDFILL METHANE OUTREACH PROGRAM

LMM-R-4

Document History

Original...July 2020

Revision.. January 2021

This paper was revised and republished in January 2021 to make the following changes and updates:

- Updated text, content of Table 2, and references in Section 4.4, subsection Average CI Comparison for Vehicle Fuels
- Corrected Figure reference in Section 8.1, subsection Cost of Pipeline Interconnection
- Removed Big Run Landfill project example in Sections 8.7 and 9.0
- Added U.S. EPA’s Biogas Toolkit to table in Section 10.0
- Corrected URLs in various locations in document, including Appendix A
- Added footnote for Main Sources of Data at end of Appendix A

Table of Contents

List of Tables

List of Figures

1.0 INTRODUCTION

EPA encourages the recovery and beneficial use of biogas as a renewable energy resource, including the production of renewable natural gas (RNG) when feasible, as a means of reducing emissions and providing other environmental benefits. RNG is a term used to describe biogas that has been upgraded to use in place of fossil natural gas, either locally or remotely. EPA's partnership programs for the reduction of methane (CH_4) emissions—the Landfill Methane Outreach Program (LMOP), AgSTAR and Natural Gas STAR—offer data on potential sources of RNG feedstocks as well as technical and outreach resources and tools to support RNG project development.

EPA developed this document to provide biogas stakeholders and other interested parties with a resource to promote and potentially assist in the development of RNG projects. This document summarizes existing RNG operational projects in the United States and the potential for growth from the main sources of biogas feedstock. This document provides technical information on how raw biogas is upgraded into RNG and ultimately delivered and used by consumers. The document also addresses barriers, policies and incentives related to RNG project development.

2.0 WHAT IS RNG?

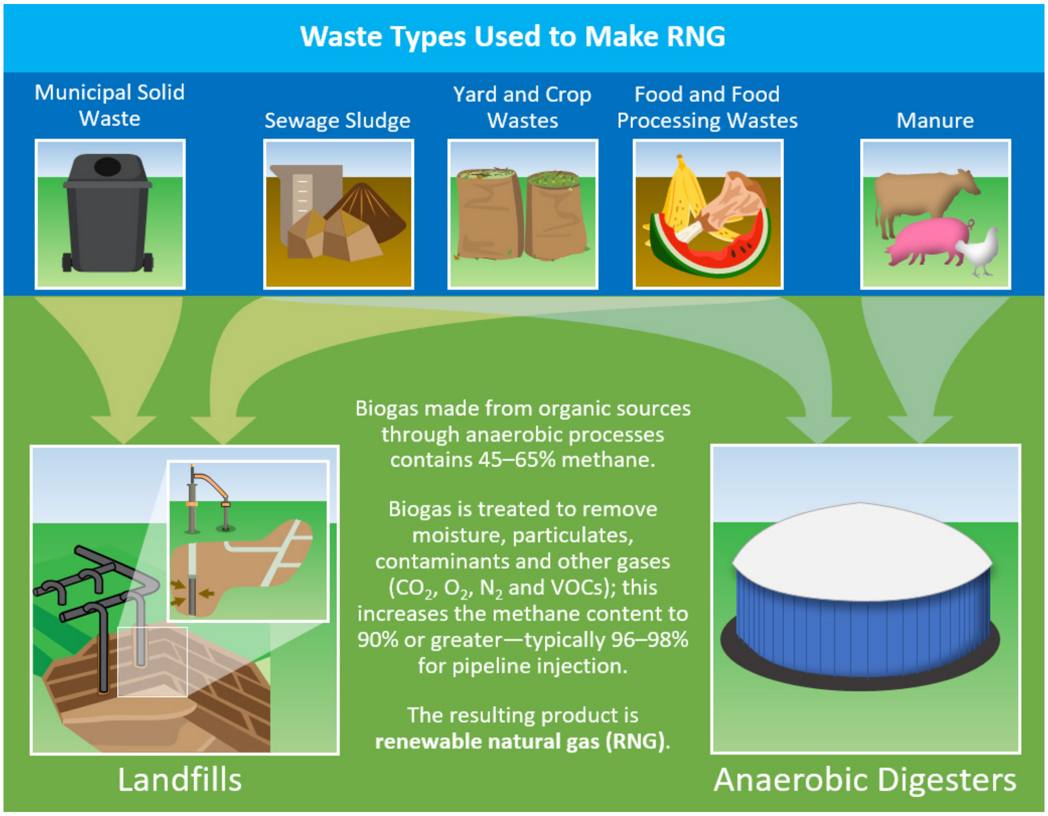
RNG is a term used to describe anaerobically-generated biogas that has been upgraded (or refined) for use in place of fossil natural gas. Raw biogas typically has a CH_4 content between 45 and 65 percent, depending on the source of the biogas, and must go through a series of steps to be converted into RNG. Treatment includes removing moisture, carbon dioxide (CO_2) and trace-level contaminants (including siloxanes, volatile organic compounds [VOCs] and hydrogen sulfide [H_2S]), as well as reducing the nitrogen (N_2) and oxygen (O_2) content. Once purified, the RNG has a CH_4 content of 90 percent or greater. RNG injected into a natural gas pipeline commonly has a CH_4 content between 96 and 98 percent.

As a substitute for fossil natural gas, RNG has many potential uses. RNG can be used as vehicle fuel, to generate electricity, in thermal applications, or as a bio-product feedstock. RNG can be injected into natural gas transmission or distribution pipelines, or it can be used locally (i.e., at or near the site where the gas is created). In this document, the term RNG does not encompass synthesis gas (syngas) produced through gasification of biomass or any other feedstocks.

2.1 Sources of RNG

Currently, there are four main sources of biogas used to produce RNG in the United States: municipal solid waste (MSW) landfills, anaerobic digestion (AD) at municipal water resource recovery facilities (WRRFs), AD at livestock farms and AD at stand-alone organic waste management operations. At each of these types of operations, biogas is produced as the organic materials are broken down by microorganisms in the absence of O_2 (i.e., anaerobic conditions). Figure 1 shows the main organic waste feedstocks that are placed into an MSW landfill or an AD facility. "Organic" in this context means the wastes come from, or were made of, plants or animals.

Figure 1. Organic Waste Types Used to Make RNG

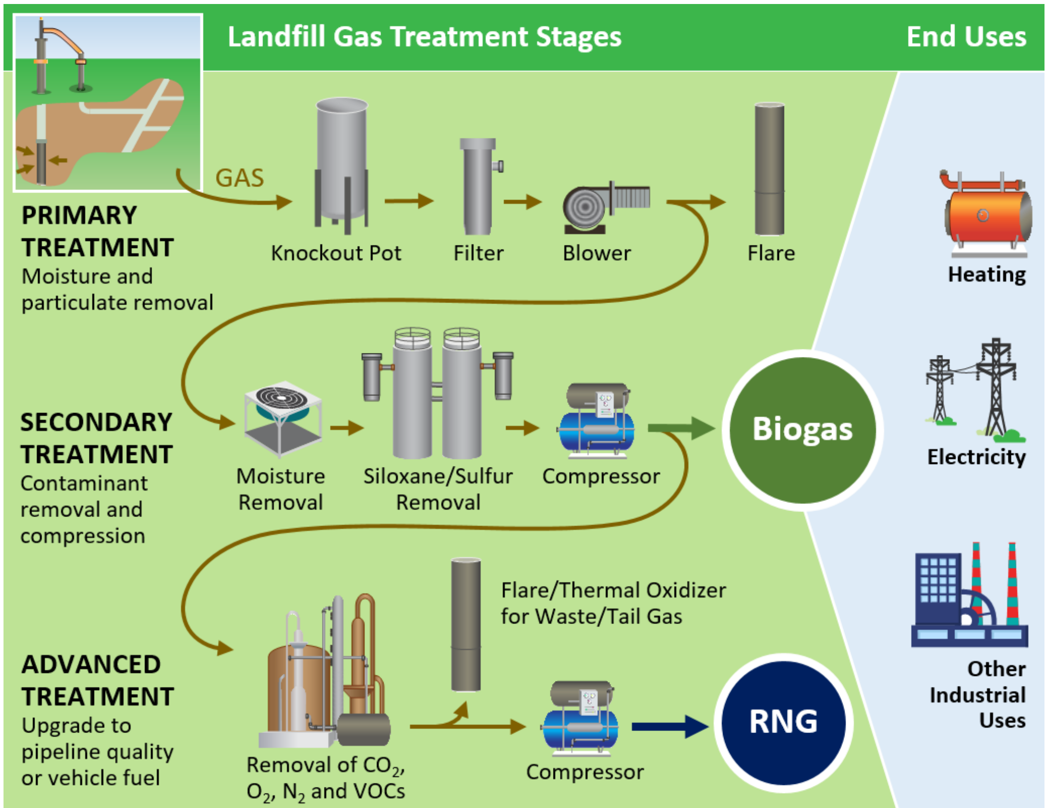


MSW Landfills

Landfill gas (LFG) is generated in MSW landfills[1] as the organic wastes decompose anaerobically. Instead of escaping into the air, LFG can be captured, converted and used as an energy resource. Applicable federal and state regulations require certain landfills to capture and destroy the LFG generated; for these sites an LFG collection infrastructure is already in place and potentially ready for an energy project. The diagram in Figure 2 provides an overview of the levels of treatment that LFG can undergo to be used as an energy resource.

[1] More information about MSW landfills is available at U.S. EPA. What Is a Municipal Solid Waste Landfill? https://www.epa.gov/landfills/municipal-solid-waste-landfills#whatis. Accessed November 18, 2019.

Figure 2. LFG Treatment Stages and Biogas End Uses



Municipal WRRFs

Many municipal WRRFs (also known as wastewater treatment facilities or publicly owned treatment works) use AD to treat sewage sludge on site, while some facilities send the sludge to other facilities for AD treatment. Biogas is one of the byproducts of sludge treatment through AD. WRRFs typically generate biogas with a high CH_4 content and extremely low N_2 and O_2 contents, which make them attractive candidates for RNG projects.

Approximately 133 to 177 WRRFs with AD were "co-digesting" other waste streams, such as source-separated food wastes, in 2017.[2] Co-digestion of food waste with WRRF sludge allows facilities to use existing assets and infrastructure to meet the growing interest in food waste management. With co-digestion, facilities can more efficiently use process equipment when they process multiple waste streams together. Facilities can also use co-digestion to adjust the proportions of solids being digested to improve digestion and increase biogas production.

Livestock Farms

Livestock farms can use AD to convert livestock (e.g., dairy, beef, swine, poultry) manure into biogas and digestate.[3] Some manure-based digesters co-digest other waste materials with the manure, including upstream (pre-consumer) food wastes such as beverage and distillery waste; fats, oils and greases;

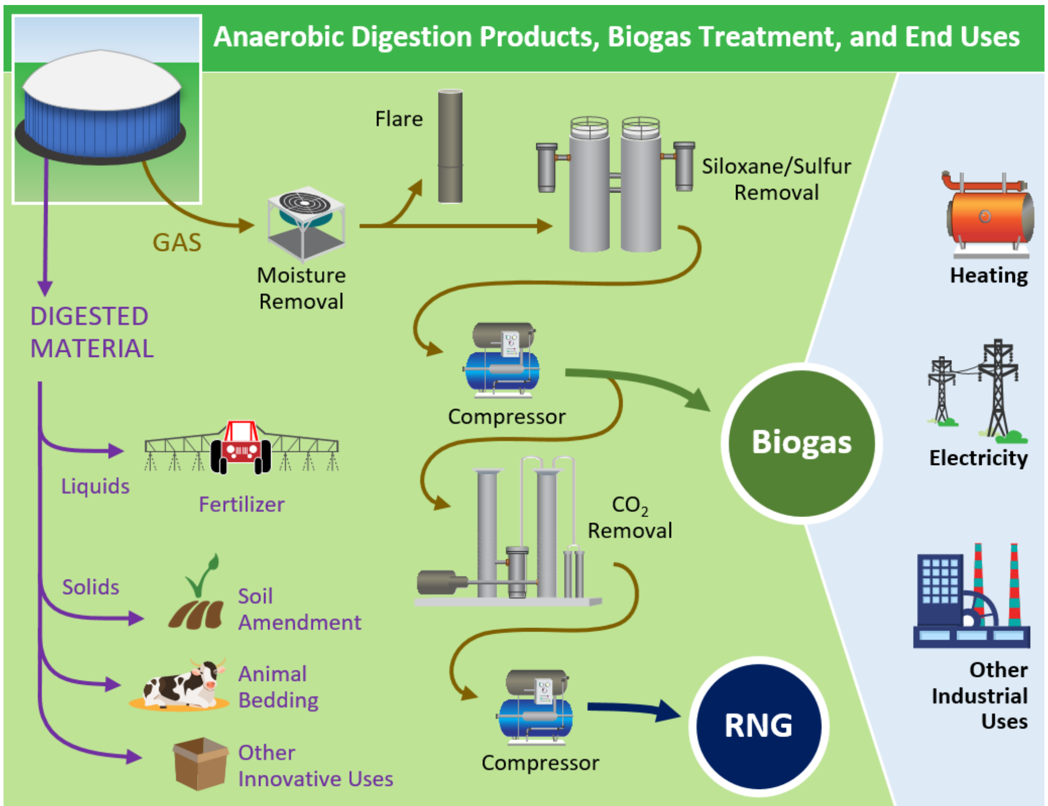
---

2 Goldstein, N. October 2017. The State of Organics Recycling in the U.S. BioCycle 58(9): 22. https://www.biocycle.net/2017/10/04/state-organics-recycling-u-s/. Accessed March 4, 2020. See Table 3 and additional discussion about data from the Water Environment & Reuse Foundation on page 6 of Goldstein's report.

3 Digestate is the nutrient-rich material left over after AD.

industrial food byproducts; or processing wastes from a dairy or slaughterhouse. Various sources estimate approximately 100 manure-based AD projects are co-digesting other organic waste materials.[4] The diagram in Figure 3 presents the biogas and typical digestate products from manure-based AD projects and the levels of treatment that AD biogas can undergo to be used as an energy resource.

Figure 3. AD Products, Biogas Treatment and End Uses



Stand-Alone Organic Waste Management Operations

Stand-alone digesters are the newest source of RNG in the United States. These AD projects break down source separated organic material—including food waste—to generate biogas, which can be converted to RNG. Digesters that primarily process food waste can also co-digest other organic materials including yard waste.[5] A 2018 EPA survey of U.S. AD facility operators showed that a total of 9.2 million tons of food waste was processed at 44 stand-alone digesters during 2016. The survey report indicates there were 62 stand-alone digesters operating in 2016, which suggests the actual amount of food waste processed in

---

[4] Goldstein, N. October 2017. The State of Organics Recycling in the U.S. BioCycle 58(9): 22. https://www.biocycle.net/2017/10/04/state-organics-recycling-u-s/. Accessed March 4, 2020. The article estimates that 94 manure-based AD projects were co-digesting. April 2017 research conducted using the AgSTAR database, case studies, articles and profiles showed 111 manure-based projects were co-digesting other materials. In March 2020, the AgSTAR database indicated 104 manure AD projects that co-digest other organic materials.

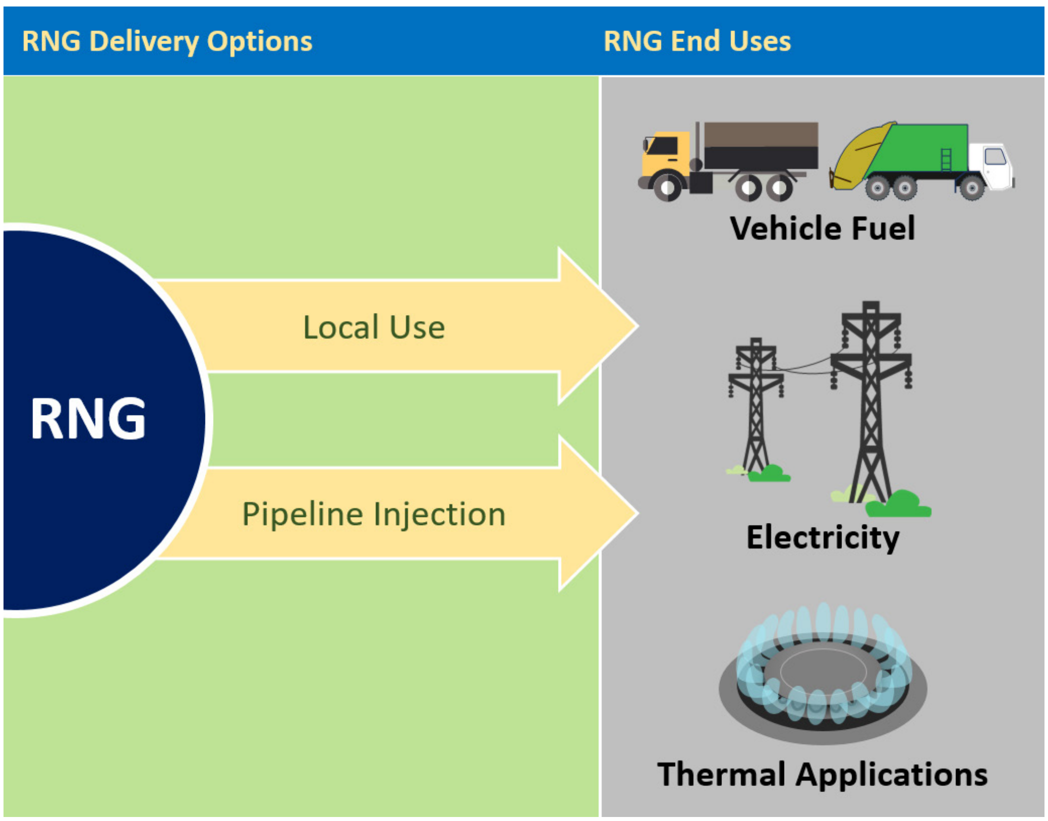
[5] U.S. EPA. Types of Anaerobic Digesters. Stand-Alone Digesters. https://www.epa.gov/anaerobic-digestion/types-anaerobic-digesters#StandAloneAD. Accessed March 25, 2019.

this manner was higher. In addition, 20 of the stand-alone digesters surveyed processed more than 31 million gallons of liquid non-food waste and nearly 83,000 tons of solid non-food waste in 2016.[6]

3.0 OPTIONS FOR RNG DELIVERY AND USE

As shown in Figure 4, the two main methods for delivering RNG to end users are injection into a pipeline (fossil natural gas pipeline or dedicated RNG pipeline) or onsite/local applications (e.g., onsite vehicle fueling station, transport by truck). RNG is so chemically similar to fossil natural gas that it is a "drop-in" substitute, making it versatile. The methane in RNG is identical to methane in fossil natural gas, but the two gasses have constituents in very low concentrations that the other does not have. In addition to being used as vehicle fuel or for generating electricity, RNG can also be used to meet thermal energy demands (heat, steam, hot water, cooling or other processes) in the industrial, commercial, institutional or residential sectors.

Figure 4. RNG Delivery Options and Typical RNG End Uses



Over time, market drivers have shaped how RNG is used. In 2011, nearly all the RNG projects operating in the United States were providing RNG to generate electricity off site, as an effect of state-level Renewable Portfolio Standard (RPS) programs.[7] As the market for renewable transportation fuels emerged through federal and state rules and incentives, the overall number of RNG projects grew rapidly and the end use

---

6 U.S. EPA. September 2019. Anaerobic Digestion Facilities Processing Food Waste in the United States (2016). EPA/903/S-19/001. https://www.epa.gov/anaerobic-digestion/anaerobic-digestion-facilities-processing-food-waste-united-states-survey.

7 Escudero, J. May 2017. Powering Businesses, Homes & Vehicles with Waste: Growing the Economy & Jobs with Renewable Natural Gas. https://www.eesi.org/files/Johannes_Escudero_052317.pdf.

of the RNG shifted dramatically. In 2017, 76 percent of RNG projects were converting RNG into transportation fuels, while 24 percent generated electricity off site.[8]

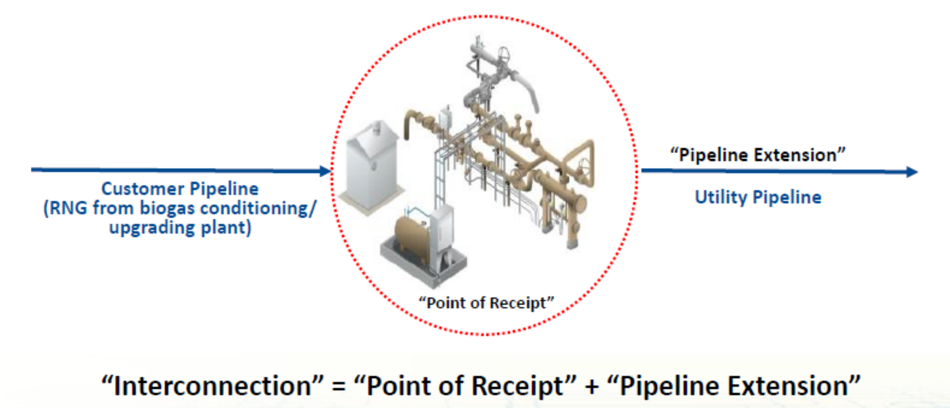
3.1 Pipeline Injection

Many RNG projects inject the product into a fossil natural gas pipeline. Appendix A lists known natural gas utilities who have received or plan to receive RNG into their networks. The RNG must meet the specification requirements of the receiving gas utility. This delivery method can be expensive due to extensive planning, land purchases, permitting, construction, and interconnection fees and equipment. However, pipeline injection can convey the RNG across a vast distribution network and provide flexibility on how and where the RNG is ultimately used.

Interconnection consists of two primary components, a "point of receipt" and a "pipeline extension," as shown in Figure 5. The point of receipt monitors the quality of the RNG to ensure that it meets specifications and includes equipment to prevent non-compliant gas from entering the pipeline. The point of receipt also meters and may odorize the RNG prior to injection. RNG can be delivered to the point of receipt from the production facility through piping built specifically for this purpose or by truck.

The pipeline extension is a dedicated pipeline to transfer the RNG from the point of receipt to the nearest fossil natural gas pipeline that has capacity to accept it. All projects have a pipeline extension to allow space for odorization, gas quality monitoring, and a shut off valve. Some distribution-level pipelines do not have the capacity to receive RNG injections (which are constant), due either to the cyclical nature of the pipeline users or to the size and volume of fossil natural gas flow. When the pipeline nearest to an RNG processing plant cannot accept the RNG, a longer pipeline extension is needed to reach a fossil natural gas pipeline with adequate capacity.[9]

Figure 5. Components of a Pipeline Interconnection[10]



[8] Escudero, J. May 2017. Powering Businesses, Homes & Vehicles with Waste: Growing the Economy & Jobs with Renewable Natural Gas. https://www.eesi.org/files/Johannes_Escudero_052317.pdf.

[9] Lucas, J. October 2017. Interconnecting to the SoCalGas Pipeline. Presented at Power of Waste: RNG for California, Sacramento. https://www.socalgas.com/1443741248177/PowerofWaste_SoCalGas_Lucas.pdf.

[10] Lucas, J. September 2017. Renewable Natural Gas Projects. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/sites/production/files/2017-10/documents/lucas_rng_2017_panel1.pdf. Figure used with permission from Southern California Gas Company.

Alternatively, RNG can be injected into a dedicated pipeline instead of into a natural gas pipeline network.

Vehicle Fuel

RNG can be used as fuel, as compressed natural gas [CNG] or liquefied natural gas [LNG], in a variety of vehicle types. According to the U.S. Department of Energy's (DOE's) Alternative Fuels Data Center, in March 2019 there were 914 public and 678 private CNG stations and 66 public and 55 private LNG stations in the country.[11]

As of March 2020, the majority (91 percent) of LFG-sourced RNG pipeline injection projects were providing at least a portion of the RNG to a vehicle fuel market down the pipeline.[12] In these cases, fueling stations far removed from the biogas source were receiving the RNG at the other end of a pipeline network.

Electricity Production

While many biogas projects generate electricity from partially conditioned biogas, there are a number of projects (primarily landfill-based) where RNG is injected into a pipeline and used to generate electricity.

Thermal Applications

Numerous biogas energy projects use nearly raw biogas in direct thermal applications such as boilers, greenhouses and kilns. RNG projects for direct thermal applications are less common, as the bulk of incentives are for transportation and electricity end uses. However, as discussed in Section 8.7, some state policies have created a new interest in RNG for direct thermal uses.

3.2 Local Use

The predominant use of RNG on site or locally is for vehicle fuel.

Onsite Vehicle Fuel

Onsite RNG vehicle fuel projects avoid the need to meet natural gas pipeline specifications, and typically the vehicle fuel specifications are less stringent than the requirements from a pipeline operator. In addition, these projects avoid the costs to interconnect and transport the gas via pipeline. However, there must be an adequate and consistent demand for the RNG vehicle fuel. Matching the fleet demand to the RNG resource can be problematic in some rural areas with a source of biogas, as larger fleets are generally located in urban centers.

Often, the owner of the biogas source also has a vehicle fleet, for example a public works department that has a landfill and/or WRRF as well as a CNG-compatible fleet inventory. Some onsite fueling stations also allow corporate fleets operating in the area to use their stations. In either case, these types of projects, wherein the vehicles delivering a feedstock (e.g., garbage or food waste) are fueled by RNG from biogas produced by that feedstock, are considered "closed loop" or circular projects.

Generally, local-use vehicle fuel projects are smaller scale than pipeline injection vehicle fuel projects. Taking LFG-based RNG as an example, the average flow rate of local-use CNG projects is 145 cubic feet

[11] U.S. DOE. Alternative Fueling Station Locator. https://afdc.energy.gov/stations/#/analyze?country=US. Accessed March 27, 2019.

[12] U.S. EPA. March 2020. Landfill and Landfill Gas Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

per minute (cfm) of biogas inlet, while the average for pipeline injection projects with a vehicle fuel component is 2,940 cfm of biogas inlet, twenty times larger.[13]

Virtual Pipeline

If an RNG processing plant is not close to potential end users or an existing pipeline, a "virtual pipeline" can move compressed RNG from the point of generation to the point of injection or use. In a virtual pipeline scenario, the RNG is compressed to up to 4,000 pounds per square inch for injection into a natural gas tube trailer, and then transported off site by truck. Once it reaches the destination, the RNG is decompressed back down to the pressure required by the receiving facility. The decompression site must include a "decant" facility that heats the RNG as it decompresses to minimize the freezing of valves and regulators due to decompression. A virtual pipeline allows remote landfills, farms or other biogas sources to market their RNG in populated areas. Leasing companies that will contract for loading, transporting and off-loading the RNG are also available. The costs to transport RNG in a virtual pipeline are in addition to the costs associated with RNG processing equipment and infrastructure needed to compress and decompress the gas.

Some projects may employ more than one delivery mechanism to match the RNG supply with demand. For example, a project may have an onsite vehicle fueling station for a portion of the fuel and transport the remainder to an offsite fueling station via a virtual pipeline.

4.0 BENEFITS OF RNG

Developing RNG resources is one way to diversify fuel supplies and increase fuel security, provide economic benefits to communities and end users, improve local air quality and reduce greenhouse gas (GHG) emissions.

4.1 Fuel Diversity and Availability

Biogas feedstocks for RNG are generated continuously from a variety of sources (offering high availability rates), and the use of RNG increases and diversifies domestic energy production. For example, Atlantic City, New Jersey used CNG-fueled buses to provide critical services in 2012 after Hurricane Sandy when gasoline supplies were limited, showing the value of alternative fuel vehicles during natural disasters.[14]

4.2 Local Economic Impacts

Developing RNG projects can benefit local economies through the construction of infrastructure and sale of vehicles that can use this fuel source. Adding a renewable source of vehicle fuel to an area has the potential to draw outside vehicle fleets to a community, as the CNG produced from biogas can potentially be sold at a lower cost than fossil fuel-based vehicle fuel (due to incentives such as EPA's Renewable Fuel Standard [RFS]) or corporations may be looking for ways to green their fleets or increase corporate sustainability.

A 2017 study conducted for the California Natural Gas Vehicle Coalition analyzed the economic impacts of converting heavy-duty diesel-fueled trucks in California to RNG fuel, including the benefits of building

13 See details and ranges of project sizes in Table 3 in Section 5.0 of this document. Data source is U.S. EPA. March 2020. Landfill and Landfill Gas Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

14 Bluestein, L. April 2013. Clean Cities Webinar: Planning Ahead with Alternative Fuels—a lesson from Sandy. https://cleancities.energy.gov/files/u/news_events/document/document_url/49/emergency_preparedness_webinar.pdf.

RNG processing and fueling station infrastructure and the impact of purchasing CNG vehicles.[15] The study found that California RNG production facilities (based on a mix of landfill, WRRF and dairy feedstocks) would generate about 8.5 to 11.2 jobs per million diesel gallon equivalent of transportation fuel. By contrast, the petroleum refinery industry yields about 1.6 jobs per million diesel gallon equivalent of transportation fuel. Additionally, for every job created through investment in low nitrogen oxide (NO_X)-emitting natural gas trucks, natural gas fueling infrastructure and RNG production facilities, about 2.0 jobs are created in supporting industries (indirect) and via spending by employees that are directly or indirectly supported by these industries (induced).

For projects where there is common ownership between the RNG source and the fleet using RNG, vehicle fuel from RNG can also provide price stability (e.g., compared to diesel fuel purchases) through mid-term to long-term RNG supply contracts or through creating fuel for internal consumption.

4.3 Local Air Quality

Replacing traditional diesel or gasoline with RNG vehicle fuel can reduce pollutant emissions, resulting in local air quality benefits.

RNG combusts similarly to fossil natural gas, so pipeline operators make no distinctions between the two once the RNG meets the required specification and is injected into the pipeline network. Fossil natural gas typically contains several non-methane hydrocarbons, including ethane, propane, butane and pentane, as well as some trace organics, all in small concentrations. RNG does not generally contain non-methane hydrocarbons but does share some other low-concentration constituents with fossil natural gas, such as CO_2, N_2, O_2, H_2S and total sulfur. Fossil natural gas and RNG both contain trace organics (e.g., aromatic hydrocarbons, aldehydes and ketones), but samples of RNG show these in much lower concentrations than in fossil natural gas.[16,17]

Since 2017, most newly built vehicles are required to meet the same emission standards (including NO_X, particulate matter [PM] and carbon monoxide [CO]) regardless of fuel type,[18] so new natural gas vehicle emissions are comparable to those of new gasoline and diesel vehicles. However, when older model gasoline or diesel vehicle fleets are replaced with new natural gas vehicles, certain local air pollutant emissions are often reduced on an as-driven basis.

For example, replacement or aftermarket conversion of older gasoline vehicles with natural gas models can provide reductions across pollutants. The Argonne National Laboratory's Alternative Fuel Life-Cycle Environmental and Economic Transportation (AFLEET) tool[19] can be used to estimate emission reductions

---

15 ICF. May 2017. Economic Impacts of Deploying Low NO_X Trucks Fueled by Renewable Natural Gas. https://www.masstransitmag.com/home/document/12330911/economic-impacts-of-deploying-low-nox-trucks-fueled-by-renewable-natural-gas.

16 Gas Technology Institute. May 2012. Guidance Document for the Introduction of Landfill-Derived Renewable Gas into Natural Gas Pipelines. https://www.gti.energy/wp-content/uploads/2018/09/120007_Landfill_Guidance_Document_FINALREPORT-05-9-2012.pdf.

17 Wiley, Kristine. October 2018. Renewable Natural Gas (RNG): Gas Quality Considerations. Presented at 2018 Natural Gas STAR and Methane Challenge Renewable Natural Gas Workshop. https://www.epa.gov/natural-gas-star-program/2018-natural-gas-star-and-methane-challenge-renewable-natural-gas-workshop.

18 U.S. EPA. Final Rule for Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards. https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-control-air-pollution-motor-vehicles-tier-3.

19 Argonne National Laboratory. November 2018. AFLEET Tool. https://afleet-web.es.anl.gov/home/. Emission estimates based on a fleet replacement location in Washington, D.C.

for fleet replacement on an as-driven basis. A fleet location of Washington, D.C., was used for illustrative purposes along with the AFLEET tool's default input parameters, including annual mileage and fuel economy. Similar patterns in emission reduction percentages were derived for other fleet locations.

The AFLEET tool was used to analyze the emissions from gasoline pickups and refuse trucks in three older model years, with model year 2010 representing a median life age for the national pickup population and model year 2012 representing a median life age for the national refuse truck population.

The results in Table 1 indicate substantial percentage reductions in NO_X, VOC, PM_{10}, $PM_{2.5}$, CO and sulfur dioxide (SO_X) emissions for each of the older gasoline pickup models, as compared with a new (model year 2019) CNG pickup, with the most significant reductions achieved for the oldest model year. For refuse trucks, substantial emission reductions were shown for NO_X, exhaust VOC, PM_{10}, $PM_{2.5}$ and SO_X, again with the largest reductions from the oldest vehicle replacements.

Table 1. AFLEET Tool Emission Results for Replacement of Washington, D.C.-Based Older Model Year Gasoline Pickups or Diesel Refuse Trucks with New (Model Year 2019) Dedicated CNG Pickups or Refuse Trucks

Fuel/Vehicle Type	Model Year	Percentage Emission Reductions if Replaced by 2019 Model Year CNG Vehicle						
		NO_X	VOC (Exhaust)	VOC (Evaporative)	PM_{10}	$PM_{2.5}$	CO	SO_X
Gasoline Pickup	2005	87.4%	86.0%	87.5%	73.0%	68.9%	84.3%	38.1%
	2007	80.2%	78.8%	85.4%	73.0%	65.0%	81.9%	38.1%
	2010	66.7%	69.1%	75.6%	66.3%	60.0%	74.6%	38.1%
Diesel Refuse Truck	2006	99.4%	93.9%	7.14%	97.0%	96.9%	-571%	43.0%
	2009	99.2%	43.8%	7.14%	42.2%	41.5%	-2,180%	43.0%
	2012	96.8%	16.9%	7.14%	38.1%	38.5%	-3,025%	43.0%

However, CO emissions increased significantly for the CNG refuse trucks relative to the diesel baseline. This increase is due to the newest CNG refuse trucks being powered by spark-ignited cycle engines with three-way catalysts. Compared to the diesel refuse trucks, which are powered by compression ignition cycle engines, the CNG spark-ignited engines operate at tightly controlled stoichiometric fuel–air ratios that allow for three-way catalyst control[20] of NO_X, VOC and CO emissions but produce inherently higher CO emissions. However, new CNG refuse trucks do still comply with existing heavy-duty engine emission standards even with the higher CO emissions. When replacing older heavy-duty diesel vehicles with new dedicated CNG vehicles, local communities should consider this trade-off of lower NO_X and PM emissions

[20] Three-way catalysts are exhaust emission control devices for achieving simultaneous control of tailpipe NO_X, VOC and CO emissions. Three-way catalysts typically are deployed in conjunction with closed loop, stoichiometric fuel–air ratio fuel delivery to the engine for achieving the highest efficiency in catalytic reduction of NO_X, and oxidation of VOCs and CO in the engine exhaust emissions stream.

but higher CO emissions with respect to existing local air quality conditions and compliance with national standards.

Apart from combustion emissions, gasoline and diesel vehicles produce hydrocarbon emissions from the evaporation of fuel in onboard fuel tanks, but natural gas vehicle fuel systems emit minimal evaporative hydrocarbon emissions because they are sealed to the atmosphere.

4.4 GHG Emission Reductions

When fossil natural gas is replaced by RNG, the resulting GHG emission reductions provide a climate benefit. One way to characterize the climate benefit of a fuel is to determine its "carbon intensity" (CI) or "carbon footprint" based on a complete life cycle assessment that estimates the GHG emissions associated with producing and consuming the fuel. Argonne National Laboratory's AFLEET tool estimates that natural gas vehicles operating on fuel derived from RNG can yield GHG emission reductions of up to 75 percent, compared to gasoline or diesel vehicles.[21] The California Air Resources Board (CARB) uses similar life cycle assessment tools to estimate the GHG emissions associated with vehicle fuels for implementation of the state's Low Carbon Fuel Standard (LCFS).

Natural gas in any form (fossil or RNG) is less carbon-intensive than the other fossil fuels it typically replaces, including conventional transportation fuels (e.g., gasoline, diesel) in most cases and coal or petroleum for generating electricity.[22,23] RNG provides an additional benefit over fossil natural gas because it generally has a lower total carbon footprint, after accounting for emissions from fuel production, transport and use.[24,25,26] RNG's carbon footprint is even lower if a project can also take into account directly reducing CH_4 emissions from the organic waste used to produce the fuel.

Fuels from some RNG feedstocks can achieve negative carbon footprints by reducing CH_4 emissions through avoiding "business-as-usual" disposal pathways, such as projects that involve AD of manure and organic wastes.[27,28] In contrast, projects in which RNG is sourced from a landfill or WRRF where business-as-usual practices collect and destroy CH_4 cannot account for any climate benefit from that CH_4 destruction. These projects can account for the emissions avoided through recovering energy that would

---

21 Argonne National Laboratory. AFLEET Tool. https://afleet-web.es.anl.gov/home/. Accessed March 4, 2020.

22 U.S. EIA. Frequently Asked Questions. How Much Carbon Dioxide Is Produced When Different Fuels Are Burned? https://www.eia.gov/tools/faqs/faq.php?id=73&t=11. Accessed March 4, 2020.

23 U.S. EPA. February 2018. Emissions & Generation Resource Integrated Database (eGRID). eGRID2016.

24 Kampman, B., C. Leguijt, T. Scholten, J. Tallat-Kelpsaite, R. Brückmann, G. Maroulis, J.P. Lesschen, K. Meesters, et al. December 2016. Optimal Use of Biogas from Waste Streams: An Assessment of the Potential of Biogas from Digestion in the EU Beyond 2020. European Commission. https://ec.europa.eu/energy/sites/ener/files/documents/ce_delft_3g84_biogas_beyond_2020_final_report.pdf.

25 Hass, H., H. Maas, R. Edwards, L. Lonza, J.F. Larivé, and D. Rickeard. January 2014. Well-to-wheels report version 4.a: JEC well-to-wheels analysis of future automotive fuels and powertrains in the European context. Report EUR 26236 EN. European Commission. https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/well-wheels-report-version-4a-jec-well-wheels-analysis.

26 Clark, C.E., J. Han, A. Burnham, J.B. Dunn, and M. Wang. December 2011. Life-Cycle Analysis of Shale Gas and Natural Gas. ANL/ESD/11-11. Argonne National Laboratory. https://greet.es.anl.gov/publication-shale_gas.

27 CARB and California Environmental Protection Agency. November 2014. Compliance Offset Protocol Livestock Projects: Capturing and Destroying Methane from Manure Management Systems. https://ww3.arb.ca.gov/cc/capandtrade/protocols/livestock/livestock.htm.

28 CARB and California Environmental Protection Agency. August 2018. Tier 1 Simplified CI Calculator Instruction Manual: Biomethane from Anaerobic Digestion of Organic Waste. https://ww3.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm.

otherwise be flared and wasted (as energy recovery is not required), however they have a positive carbon footprint overall.

Average CI Comparison for Vehicle Fuels

Using data from pathways that CARB has certified under the LCFS for 2021, Table 2 provides a comparison of average CIs for several renewable vehicle fuels to fossil-based fuels.

Table 2. CI Ranges of Fossil and Renewable Vehicle Fuels from CARB LCFS-Certified Pathways[29]

Fuel Category [a]	Feedstock	Average CI ($g\ CO_2e/MJ$) [b]	Range ($g\ CO_2e/MJ$)	Number of Pathways
Diesel	Fossil Crude	100	100	1
CNG, Fossil	Fossil Natural Gas	79	79	1
LNG, Fossil	Fossil Natural Gas	No data	--	--
CNG, Renewable	LFG	53	30 to 83	30
	Manure	-313	-533 to -151	24
	Wastewater	47	37 to 58	3
	Food and Green Waste	No data	--	--
LNG, Renewable	LFG	61	43 to 80	14
	Manure	-336	-360 to -312	3
	Wastewater	48	42 to 55	2
	Food and Green Waste	No data	--	--

a CARB accounts for relative energy efficiencies of different drive technologies relative to the baseline gasoline or diesel technologies by using energy economy ratios (EERs). EERs account for differences in fuel efficiency for a given vehicle type and alternative transportation fuel and compares it to a benchmark, conventional vehicle. Vehicle type- and fuel-specific EERs should be applied to average fuel CIs to facilitate comparison across fuel types. The average CI values provided in this table do not yet have EERs applied to them. [30]

b The exact CI of diesel is 100.45 grams of CO_2 equivalent per megajoule ($g\ CO_2e/MJ$), per CARB documentation.

The CIs of fuels from different RNG feedstocks and fossil natural gas are characterized by impacts occurring at distinct phases of the fuel life cycle. For example, tailpipe emissions of CO_2 from RNG fuels are considered carbon neutral because the carbon is biogenic, while tailpipe emissions of CO_2 from fossil natural gas fuels are not. As a result, CIs of fossil natural gas-based vehicle fuels are most impacted by tailpipe emissions, with lesser contributions from refining and resource extraction. As another example, RNG fuels derived from LFG receive no credits for CH_4 reduction under the LCFS because the baseline set by CARB for this pathway is flaring of the LFG. As a result, LFG-derived vehicle fuels have CIs that are most heavily influenced by the biogas upgrading plant and emissions during pipeline transport.[31] The exact CI

---

29 CARB. LCFS Pathway Certified Carbon Intensities. https://www.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm. File provided by CARB on December 3, 2020. CARB updates the pathway file regularly.

30 California Code of Regulations. 2020. Title 17. Public Health. Division 3. Air Resources. Chapter 1. Air Resources Board. Subchapter 10. Climate Change. Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions. Subarticle 7. Low Carbon Fuel Standard. Section 95486. Generating and Calculating Credits and Deficits. May 27, 2020. https://govt.westlaw.com/calregs/Index?transitionType=Default&contextData=%28sc.Default%29. Accessed September 3, 2020.

31 CARB and California Environmental Protection Agency. 2018. Tier 1 Simplified CI Calculator for Biomethane from North American Landfills. https://ww3.arb.ca.gov/fuels/lcfs/ca-greet/ca-greet.htm. Accessed March 4, 2020.

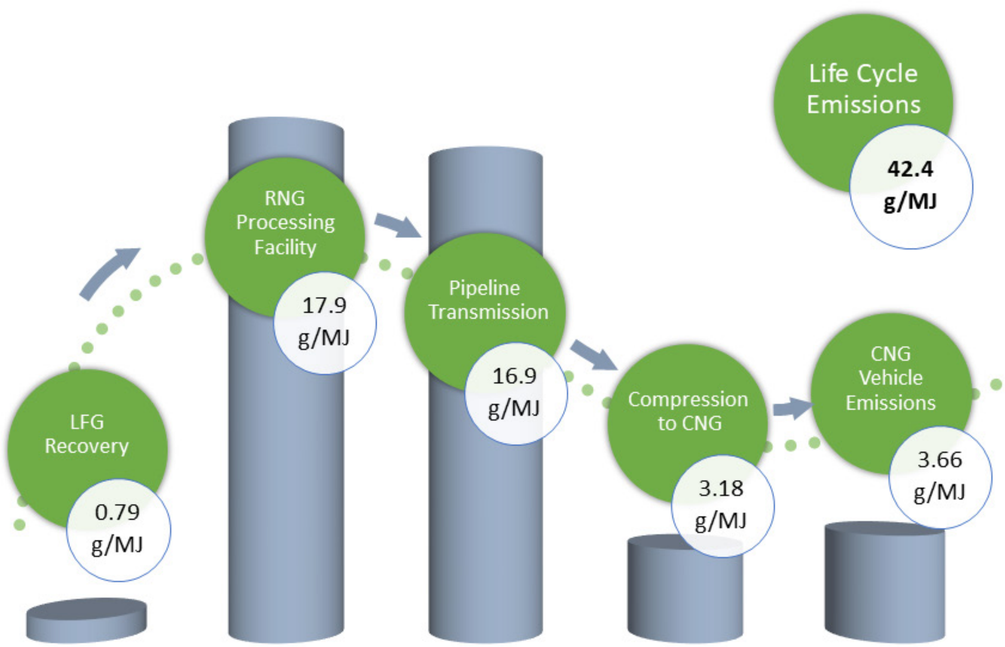
used to power the gas upgrading equipment and compression in the pipeline, as well as the length of the transmission pipeline.

CIs for a Hypothetical LFG-to-CNG Project

Figure 6 illustrates example CIs associated with each major step in a hypothetical LFG-to-CNG project: LFG recovery at the landfill, treatment/processing of the raw LFG into RNG, transporting the RNG via pipeline networks to the CNG fueling stations, compression of the RNG at CNG fueling stations and emissions from the CNG vehicles. These example CIs were determined using CARB's Tier 1 Simplified CI Calculator for Biomethane from North American Landfills with the following inputs and assumptions:

- Input of 3,100 cfm raw LFG at 50 percent CH_4.
- RNG processing plant that:
    - Is powered by grid-purchased electricity.
    - Does not require any supplemental propane or fossil natural gas to achieve the target specifications for pipeline injection of the RNG.
    - Has an energy consumption of 0.009 kilowatt-hours per standard cubic foot (scf) of LFG and a 90 percent capture efficiency of CH_4, yielding 455 British thermal units (Btu) of RNG per scf (Btu/scf) of LFG.
- Three thousand miles of gas pipeline to transport the RNG from the landfill to the CNG fueling stations.
- U.S. average mix for the energy used to power the LFG recovery equipment, RNG upgrading/processing plant and transport of the LFG via pipeline.
- California grid mix for the energy used to compress RNG at the CNG fueling station.

Figure 6. Example CIs from LFG-RNG-CNG Life Cycle (g CO_2e/MJ)



LMM-R-4

4.5 Other Benefits of Natural Gas Vehicles

Natural gas vehicles, including those using RNG-derived fuel, offer other benefits to the community. Members of the public often view local green programs positively, which can present great marketing and publicity opportunities for a community. According to Clean Energy Fuels, dedicated natural gas-fueled refuse trucks produce less noise than comparable diesel-fueled refuse trucks, with a difference greater than 10 decibels at idle.[32] Reducing noise from trucks has positive and measurable health and economic benefits.[33]

5.0 OPERATIONAL RNG PROJECTS

Across all feedstocks, 34 states have more than 100 RNG projects operating and approximately 40 under construction as of February 2020.[34] EPA provides a national map showing the locations of projects producing RNG from either LFG or manure-based AD biogas.[35]

MSW Landfills

According to the EPA LMOP Landfill and LFG Energy Project Database, as of March 2020 there were 564 operational LFG energy projects, 65 of which produced RNG.[36] Table 3 provides a summary of the 65 LFG-to-RNG projects in the United States, including the number of projects and their sizes in terms of the amount of LFG used to create the RNG. The majority of these projects are producing RNG for use as transportation fuel, whether used locally (on site or near the landfill) or transported via pipeline to a location further away. The other projects use the RNG to generate electricity in thermal applications or to offset fossil natural gas usage in another manner.[37]

The first LFG-to-RNG project in the United States operated from 1975 to 1985 at the Palos Verdes Landfill in Los Angeles County, California.[38,39] The plant was designed to process 2 million standard cubic feet per day (mmscfd) of raw LFG into approximately 1 mmscfd of RNG for injection into a nearby pipeline.[40]

32 Clean Energy Compression. July 2015. What Refuse Truck Fleets Are Doing to Make Our Air Cleaner. https://www.cleanenergyfuels.com/compression/blog/refuse-truck-fleets-switch-natural-gas-power-who-when-where-why/.

33 Pignier, N. May 2015. The Impact of Traffic Noise on Economy and Environment: A Short Literature Study. KTH Royal Institute of Technology. https://www.diva-portal.org/smash/get/diva2:812062/FULLTEXT01.pdf.

34 Coalition for Renewable Natural Gas. RNG Production Facilities Database. http://www.rngcoalition.com/rng-production-facilities. Accessed February 11, 2020.

35 U.S. EPA. RNG Project Map. https://www.epa.gov/lmop/renewable-natural-gas#rngmap. Accessed July 22, 2019.

36 U.S. EPA. March 2020. Landfill and Landfill Gas Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

37 U.S. EPA. March 2020. Landfill and Landfill Gas Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

38 Cosulich, J., S.-L. Ahmed, and J.F. Stahl. 1992. Palos Verdes Landfill Gas to Energy Facility. http://gwcouncil.org/publications/nawtec/proceedings-of-15th-biennial-conference/.

39 Bowerman, F., N. Rohatgi, K. Chen, and R. Lockwood. July 1977. A Case Study of the Los Angeles County Palos Verdes Landfill Gas Development Project. EPA/600/3-77/047. https://cfpub.epa.gov/si/si_public_record_Report.cfm?Lab=ORD&dirEntryID=49543.

40 U.S. DOE. March 1978. Proceedings of a Symposium on the Utilization of Methane Generated in Landfills. https://www.osti.gov/biblio/6652887.

Table 3. Breakdown of LFG-to-RNG Project Types and Sizes in the United States from the LMOP Landfill and LFG Energy Project Database

RNG Delivery Method / Project Type	Number of Projects	Project Size LFG Flow (cfm)
Local / CNG	6	49 to 201 (average 145)
Local / LNG	1	2,410
Pipeline Injection / Vehicle Fuel	53	413 to 10,417 (average 2,753)
Pipeline Injection / Industrial, Electricity or Other	5	757 to 5,833 (average 2,940)

Municipal WRRFs

In 2013, about 48 percent of the total wastewater flow in the United States was treated through AD.[41] According to the U.S. GHG Inventory, in 2017 approximately 18,260 million gallons per day (MGD) of wastewater effluent were sent to WRRFs with AD.[42] In 2019, 13 WRRF biogas projects (listed in Table 4) were creating RNG.[43,44]

Table 4. WRRF Digester Gas-to-RNG Projects Operating in the United States in 2019

WRRF Project Location	Start Year	WRRF Average Flow Rate in MGD
91st Avenue, Phoenix, AZ	2019	138
City of San Mateo, CA	2016	15.7
Las Gallinas Valley Sanitary District, CA	2017	2.67
Point Loma, CA	2012	175
Persigo (Grand Junction), CO	2015	8.5
South Platte Water Renewal Partners, CO	2019	~24
Honouliuli, HI	2016	26.1
Dubuque, IA	2017	7
Warrior Biogas Reuse Project, KS	2018	5.5
Newark, OH	2011	8
San Antonio Water Systems, TX	2010	94.7
South Treatment Plant, WA	1987	70
Janesville, WI	2012	13

Livestock Farms

According to the EPA AgSTAR project database, as of March 2020 there are 255 operational digester projects that accept livestock manure. The majority (79 percent) of the manure-based digester projects

---

41 U.S. DOE. July 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy. https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

42 Working spreadsheet for 2017 U.S. GHG Inventory for Wastewater Treatment.

43 Mintz, M., P. Vos, M. Tomich, and A. Blumenthal. October 2019. Database of Renewable Natural Gas (RNG) Projects: 2019 Update. Argonne National Laboratory. https://www.anl.gov/es/reference/renewable-natural-gas-database.

44 Gilbert, D. November 2019. "Biogas" Project Up and Running at Wastewater Plant. https://littletonindependent.net/stories/biogas-project-up-and-running-at-wastewater-plant,288922.

are at dairy farms, and 14 percent are at swine farms. The remainder process a mix of animal manure effluents, including those from poultry and beef cattle.[45]

The earliest U.S. manure-based digester project to create RNG began in 2004 at Whitesides Dairy in Idaho. The Whitesides project was the first biogas production facility at a large commercial dairy in the state and provided approximately 10 million cubic feet of RNG annually to Intermountain Gas until 2009, when the project ended.[46]

The majority (84 percent) of manure-based digester projects are generating electricity, and many of them are also recovering waste heat in combined heat and power[47] (or cogeneration) projects. More than 20 manure-based digester projects are currently producing RNG from their biogas with a variety of RNG end uses including electricity, vehicle fuel and pipeline gas. [48]

Organic Waste Management Operations

EPA's 2018 AD survey results show that of the 43 stand-alone facilities that reported on their biogas end use, five produce CNG for either company vehicles or for sale to other customers, while none provide RNG for pipeline injection.[49]

6.0 CONSIDERATIONS FOR PROJECT FEASIBILITY AND POTENTIAL FOR GROWTH

In addition to the sites discussed in Section 5.0 that are recovering biogas as a renewable energy resource, there are many other biogas-producing sites in the United States that could potentially capture their biogas for energy. Based on market conditions and incentives, several of the sites already recovering biogas for electricity generation or other applications could switch to producing RNG instead; several LFG energy projects have already made this change. In addition, more organic waste in this country could be digested for energy recovery instead of being landfilled. A subset of the sources in these categories could produce RNG.

Considerations for the feasibility of an RNG project include:

- The quantity and quality of biogas available for conversion (e.g., LFG and WRRF biogas tend to require more constituent removal than manure-based or organic waste AD projects);
- Economic considerations (e.g., financing options, available incentives);
- End user availability for the RNG (e.g., proximity to a fossil natural gas pipeline without physical connection barriers, a local distribution company's interest in taking RNG, a local vehicle fuel demand, a natural gas-consuming business with sustainability goals); and
- A reliable power source for the compression and cleanup processes.

---

45 U.S. EPA. March 2020. Livestock Anaerobic Digester Database. https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

46 U.S. EPA. March 2020. Livestock Anaerobic Digester Database. https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

47 Combined heat and power or cogeneration projects recover and beneficially use the waste heat from the combustion unit that is generating electricity, thus providing a greater overall efficiency.

48 U.S. EPA. March 2020. Livestock Anaerobic Digester Database. https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

49 U.S. EPA. September 2019. Anaerobic Digestion Facilities Processing Food Waste in the United States (2016). EPA/903/S-19/001. https://www.epa.gov/anaerobic-digestion/anaerobic-digestion-facilities-processing-food-waste-united-states-survey.

Higher flows of biogas (e.g., greater than 1,000 cfm for LFG-sourced projects) are needed for pipeline injection projects to be financially feasible, but local-use RNG-to-vehicle fuel projects are feasible at lower flows (e.g., as low as 50 cfm for LFG-sourced projects). Gas conditioning technology improvements have allowed smaller biogas volumes to be economically treated when used directly in onsite vehicle fueling stations or aggregated with output from other sites to make use of one fossil natural gas pipeline interconnect.

Prior to implementing any type of biogas energy project, an end user (or buyer of environmental attributes) must be identified and appropriate agreements must be in place. For RNG projects, if onsite vehicle fueling, direct pipeline injection or virtual pipeline transport is not feasible, an otherwise attractive project may not be viable.

MSW Landfills

There is a significant opportunity for growth in RNG from LFG. LMOP defines a "candidate" landfill as a landfill that is currently accepting waste or has been closed five years or less, has at least one million tons of waste, and does not have an operational, under-construction or planned LFG energy project. A landfill can also be designated as a candidate landfill based on actual interest for a project at the site. As of March 2020, there were approximately 480 candidate landfills with the potential to collect a combined 500 mmscfd of LFG. Out of these 480 landfills, approximately 375 have between 100 and 1,000 cfm of LFG available, and approximately 90 have greater than 1,000 cfm of LFG. There are also landfills with operational energy projects that are flaring excess LFG—approximately 85 of these landfills have 100 to 1,000 cfm of excess gas, and approximately 30 have more than 1,000 cfm of excess gas.[50]

Municipal WRRFs

A 2014 National Renewable Energy Laboratory report analyzed flow rate data from approximately 18,000 WRRFs to estimate their CH_4 potential. After subtracting out the biogas used for combined heat and power projects at WRRFs, the National Renewable Energy Laboratory estimated 1.9 million metric tons of CH_4 available for recovery from these facilities.[51]

The Water Environment Federation (WEF) maintains a "phase 1" database that lists information for approximately 1,250 WRRFs that have AD on site or send sludge to another facility to be treated by AD.[52] The economic viability of a WRRF biogas project primarily depends on the amount of organic feedstock (e.g., wastewater sludge, commercial or industrial waste) that is available for AD. Typically, a larger WRRF (in terms of influent flow) has a greater opportunity for biogas capture and use. In March 2015, Argonne National Laboratory analyzed data in the WEF database, which included a summary of the counts of biogas utilization projects for varying WRRF capacities, as shown in Table 5.

50 U.S. EPA. March 2020. Landfill and Landfill Gas Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

51 Saur, G., and A. Milbrandt. July 2014. Renewable Hydrogen Potential from Biogas in the United States. NREL/TP-5400-60283. https://www.nrel.gov/docs/fy14osti/60283.pdf.

52 WEF. 2015. Biogas Data. http://www.resourcerecoverydata.org/biogasdata.php. Accessed March 27, 2019.

Table 5. Number of Biogas Utilization Projects for Varying WRRF Capacities[53]

WRRF Average Flow Rate in MGD	Number of WRRFs with AD	Number Using Biogas / Number Not Using Biogas
<1	96	55 / 41
1 to 10	690	505 / 185
10 to 100	276	238 / 38
100 to 1,000	29	26 / 3

The WEF database contains approximately 5,100 WRRFs in total, so it does not represent the entire list of operating WRRFs nationwide, which is between 15,000 and 18,000 WRRFs.[54] Of the WRRFs in the WEF database, 3,200 have an average flow rate greater than 1 MGD; more than 60 percent of these facilities do not send solids to AD, and therefore do not produce biogas. There are 12,000 facilities with average flow rates less than 1 MGD, and only a small number of these facilities have AD;[55] WRRFs of this size are not expected to support an RNG project.

The project information in Table 4 of this document shows that of the 13 WRRF biogas-to-RNG projects operating in 2019, about half are at WRRFs greater than 15 MGD in average flow rate. Table 5 notes 185 WRRFs with average flow rates between 1 and 10 MGD that have AD but are not beneficially using the biogas; these WRRFs could potentially use their biogas for a local-use RNG project if demand is present. For the 41 WRRFs with average flow rates greater than 10 MGD that have AD but are not using the biogas for energy, they likely could produce RNG from their biogas for either local or pipeline delivery if other project considerations are favorable. There is likely additional RNG generation potential at WRRFs not represented in the WEF database.

Livestock Farms

Candidate sites are generally considered to be dairies with at least 500 cows or swine facilities with at least 2,000 sows or feeder pigs. This is a rough estimate that accounts for the general manure production rates and composition of these animals and should only be used for general screening, since smaller operations have been successfully developed into beneficial use applications. According to estimates from

53 U.S. DOE. July 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy. https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf. Citing Shen, Y., J.L. Linville, M. Urgun-Demirtas, M.M. Mintz, and S.W. Snyder. 2015. An Overview of Biogas Production and Utilization at Full-Scale Wastewater Treatment Plants (WWTPs) in the United States: Challenges and Opportunities Towards Energy-Neutral WWTPs. Renewable & Sustainable Energy Reviews 50: 346–62. The WRRF counts in Table 5 sum to fewer than the count of 1,250 WRRFs noted in the text; the remaining ~150 WRRFs in the WEF database that were not noted in the 2015 Argonne study are presumed to have not had sufficient average flow rate data to be categorized by size.

54 Lono-Batura, M., Y. Qi, and N. Beecher. December 2012. Biogas Production and Potential from U.S. Wastewater Treatment. BioCycle 53(12): 46. https://www.biocycle.net/2012/12/18/biogas-production-and-potential-from-u-s-wastewater-treatment/. Citing U.S. EPA 2008 Clean Watershed Needs Survey.

55 Lono-Batura, M., Y. Qi, and N. Beecher. December 2012. Biogas Production and Potential from U.S. Wastewater Treatment. BioCycle 53(12): 46. https://www.biocycle.net/2012/12/18/biogas-production-and-potential-from-u-s-wastewater-treatment/.

DOE, nearly 1.5 billion cubic feet of digester gas from farms that could be recovered for energy are flared each year.[56]

AgSTAR estimates that more than 8,000 large swine or dairy farms could create RNG from manure-based digesters, including nearly 800 dairies in California alone (the largest dairy-producing state).[57] As of March 2020, there were approximately 10 dairy digester projects under construction in California and another 31 under development.[58] If all 8,000 of the candidate farms produced and captured biogas to produce RNG, AgSTAR estimates they could create the equivalent of 1.3 billion diesel gallons, enough to fuel nearly 150,000 refuse trucks.[59]

Organic Waste Management Operations

EPA reports that about 94 percent of the food that is thrown away in this country is either landfilled or combusted for energy. Of the 40.7 million tons of food waste generated in 2017, 30.6 million tons were landfilled and 7.5 million tons were combusted with energy recovery. The remaining approximately 2.6 million tons were composted.[60] In 2015, EPA and the U.S. Department of Agriculture created the U.S. 2030 Food Loss and Waste Reduction Goal, which includes a goal to reduce food waste going to landfills or combustion with energy recovery by 50 percent over a 2010 baseline.[61]

AD facilities can process food waste that would otherwise be landfilled or combusted. In 2015, it was estimated that the number of stand-alone AD facilities could double in the next five to ten years, while processing capacity could quadruple in the next five years.[62] It is also estimated that AD of 100 tons of organic waste per day can generate enough biogas to create between 900 and 1,400 gasoline gallon equivalents (GGE) of CNG per day, depending on the type of organic waste, AD technology used and CH_4 capture efficiency of the RNG technology used.[63,64,65]

---

56 U.S. DOE. July 2016. 2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy. https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

57 U.S. EPA. June 2018. Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities. https://www.epa.gov/sites/production/files/2018-06/documents/epa430r18006agstarmarketreport2018.pdf.

58 U.S. EPA. March 2020. Livestock Anaerobic Digester Database. https://www.epa.gov/agstar/livestock-anaerobic-digester-database.

59 U.S. EPA. June 2018. Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities. https://www.epa.gov/sites/production/files/2018-06/documents/epa430r18006agstarmarketreport2018.pdf.

60 U.S. EPA. November 2019. Advancing Sustainable Materials Management: 2017 Fact Sheet. EPA/530/F-19/007. https://www.epa.gov/facts-and-figures-about-materials-waste-and-recycling/advancing-sustainable-materials-management.

61 U.S. EPA. United States 2030 Food Loss and Waste Reduction Goal. https://www.epa.gov/sustainable-management-food/united-states-2030-food-loss-and-waste-reduction-goal. Accessed March 5, 2020.

62 EREF. August 2015. Anaerobic Digestion of Municipal Solid Waste: Report on the State of Practice.

63 U.S. EPA. March 2008. Anaerobic Digestion of Food Waste. Final Report. Table ES-1. https://nerc.org/documents/anaerobic_digestion_report_march_2008.pdf.

64 U.S. EPA. May 2017. LFGcost-Web. Version 3.2. https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model.

65 U.S. EPA. May 2019. Documentation for Greenhouse Gas Emission and Energy Factors Used in the Waste Reduction Model (WARM). Organic Materials Chapters. https://www.epa.gov/sites/production/files/2019-06/documents/warm_v15_organics.pdf.

7.0 PURIFICATION PROCESSES AND GENERAL TECHNOLOGIES

Raw biogas, which is typically between 45 and 65 percent CH_4 depending on the feedstock, must go through a series of steps to be converted into RNG (at 90 percent CH_4 or greater, depending on the specification for the pipeline or other end use). Constituents of RNG that most often have specifications or limits to meet are CO_2, O_2, inert gases (including N_2), total sulfur, H_2S, siloxanes and VOCs. Other properties that are prescribed by pipelines or end users include heating value, temperature, pressure and moisture content.

Typical steps to convert raw biogas to RNG are reviewed below. As shown in Figure 2 and Figure 3, the treatment can be divided into:

- Primary: basic moisture and particulate removal.
- Secondary: additional moisture removal, contaminant removal and compression.
- Advanced: CO_2, O_2, N_2 and VOC removal and further compression.

The primary and secondary treatment stages produce a medium-Btu gas, which means the heating value of the gas is less than that of fossil natural gas (typically about half). The advanced treatment stage produces RNG, with a heating value similar to fossil natural gas.

As part of advanced treatment, some CH_4 is stripped out along with the CO_2 and other residual constituents—especially H_2S—and routed to a flare or thermal oxidizer for destruction. The amount of CH_4 stripped out as "tail gas" depends on the technology used to upgrade the gas, the ultimate CH_4 specification for the RNG and the cost–benefit ratio of additional CH_4 capture versus the additional capital expense to achieve it.

Primary Treatment

Primary treatment consists of basic moisture and particulate removal from the raw biogas. The gas passes through a knockout pot, filter and blower to remove moisture. This treatment is all that is required for destroying the LFG in a combustion flare; in addition, some LFG energy projects have used only primary treatment when combusting LFG in medium-Btu applications such as leachate evaporators, boilers and kilns.

Secondary Treatment

Secondary treatment consists of additional moisture removal, contaminant removal and compression. The process first uses an after cooler to condense and remove additional moisture, then removes contaminants such as siloxanes and sulfur. The type of contaminants removed depends on the end use and which constituents are present in the biogas and at what levels. The gas can also be compressed further as needed. These secondary treatments are used to produce medium-Btu gas for direct thermal applications such as boilers or for electricity generation applications such as engines and turbines.

Advanced Treatment

Advanced treatment is critical to transform biogas into RNG. Advanced treatment must remove CO_2, O_2, N_2, VOCs and siloxanes (as needed), although some projects may remove these types of contaminants in an earlier stage. The selection of the advanced treatment technology type is site-specific and project-specific, and there are advantages and disadvantages to each type. Sections 7.1 through 7.4 describe advanced treatment technologies in detail, along with their benefits and drawbacks.

Fuel Specifications

For pipeline injection projects, regardless of the eventual end use at the other end of a pipeline network, there is typically a higher CH_4 content specification to meet than for onsite vehicle fuel projects. As a result, these projects usually recover a higher fraction of the CH_4, typically in the 96 to 98 percent range. Pipeline specifications also put low limits on the levels of O_2 and inert gases that are allowed in the RNG.[66] Tail gas from these projects must be destroyed in a flare or thermal oxidizer, using supplemental fuel since tail gas does not have a sufficient heating value to sustain combustion.

In the United States, CNG vehicle fuel project developers generally design projects to meet the technical requirements set by the Society of Automotive Engineers *Surface Vehicle Recommended Practice J1616™ for Compressed Natural Gas Vehicle Fuel* (SAE J1616). SAE J1616 sets minimum requirements for CNG fuel composition and properties to ensure vehicle, engine and component durability, safety and performance. It provides technical requirements for several fuel properties and potential constituents including CH_4, sulfur compounds, O_2 and particulate material. SAE J1616 references CARB's CNG commercial fuel composition for several specifications, including 88 percent CH_4 (minimum) and 1 percent O_2 (maximum).[67]

7.1 CO_2 Removal Technologies

There are four common ways to remove CO_2 during the advanced treatment stage: membranes, pressure swing adsorption (PSA), solvent scrubbing and water scrubbing. Each technology has strengths and weaknesses that are evaluated and balanced on a case-by-case basis for each potential RNG facility to select the technology best suited for that particular site. Each technology can achieve RNG quality standards necessary for pipeline injection or onsite vehicle use, but it is often a matter of upfront capital expense versus ongoing operating expense.

Based on 2018 data in Argonne National Laboratory's database of RNG projects, the CO_2 removal technology distribution for RNG projects at landfills in the United States was 27 percent using solvent scrubbing, 24 percent using membrane systems, 10 percent using PSA and 8 percent using both membranes and PSA, with the balance using water scrubbing or an unknown technology. For manure-based AD biogas-to-RNG projects in the United States in 2018, 64 percent were using membrane systems, 12 percent were using PSA and 6 percent were using water scrubbing, with the balance using another technology.[68] Figure 7 and Figure 8 show these breakdowns in chart form.

---

66 Smyth, P., and J. Pierce. January 2011. Quantification of the Incremental Cost of Nitrogen and Oxygen Removal at High-Btu Plants. Presented at 14th Annual EPA LMOP Conference and Project Expo. p. 33. https://www.epa.gov/sites/production/files/2016-06/documents/smyth.pdf.

67 Society of Automotive Engineers International. March 2017. Recommended Practice for Compressed Natural Gas Vehicle Fuel. Surface Vehicle Recommended Practice J1616™. Section 4, Technical Requirements, and Appendix D, Table D.2, CARB Commercial Fuel Composition. https://www.sae.org/standards/content/j1616_201703/.

68 Mintz, M., P. Vos, M. Tomich, and A. Blumenthal. October 2019. Database of Renewable Natural Gas (RNG) Projects: 2019 Update. Argonne National Laboratory. https://www.anl.gov/es/reference/renewable-natural-gas-database.

Figure 7. CO_2 Removal Technologies for U.S. LFG-to-RNG Projects in 2018

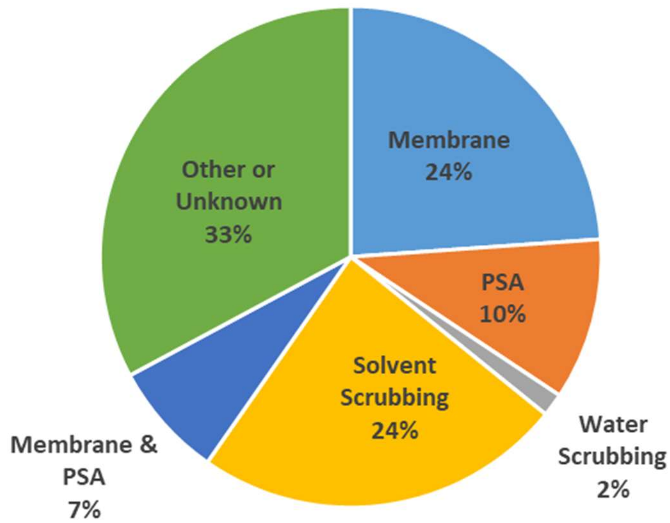
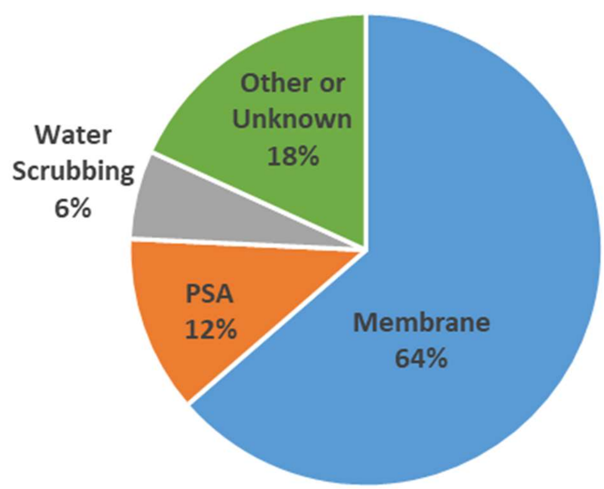


Figure 8. CO_2 Removal Technologies for U.S. Manure-Based Biogas-to-RNG Projects in 2018



By comparison, Europe had more than 80 RNG projects in 2014, with approximately 65 percent of the projects using water or solvent scrubbing, 23 percent using PSA and 11 percent using membranes.[69]

---

[69] U.S. EPA. September 2016. Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies. EPA/600/R-16/099. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100QCXZ.PDF?Dockey=P100QCXZ.PDF.

Membrane Systems

A membrane is a type of filter that has a specific pore size rating and operates similarly to a screen or sieve, retaining particles larger than the membrane's pore size. The material that the membrane is constructed from and the method by which the large particles are captured is technology specific. Membranes are often used to remove CO_2 and other unwanted constituents when upgrading raw biogas to RNG.

Single-Pass Membrane System

Onsite CNG vehicle fuel use typically does not require a heating value as high as that required by pipeline injection projects, and it also allows some minor levels of O_2 and inert gases. Therefore, onsite vehicle fuel applications with smaller biogas volumes often use a single-pass membrane system that captures approximately 65 to 80 percent of the CH_4. These systems either send the remaining 20 to 35 percent of the CH_4 out as tail gas for economical destruction in an onsite flare or blend it with the remaining biogas for use in turbine or reciprocating engine electrical generating equipment. More efficient gas conditioning technology that would produce a gas with a higher heating value is available for small biogas flows, but historically it has not been economically feasible due to the added capital expense.

Multiple-Pass Membrane System

Larger-scale onsite vehicle fuel applications can use membrane technology similar to that of smaller-scale applications, but with more efficient processes that capture additional CH_4 via multiple passes through the membranes. Many of these sites use gas conditioning technology that captures approximately 96 to 99 percent of the CH_4. Tail gas from these projects must be destroyed in a flare or thermal oxidizer using supplemental fuel, since the tail gas does not have a sufficient heating value to sustain combustion.[70] The increased volume of RNG produced from conditioning larger biogas volumes can typically justify the added capital and operational expenses and the addition of a thermal oxidizer.

PSA

In PSA systems, adsorbent media are pressurized with the incoming biogas. A difference in molecular size allows CH_4 to pass through into the product gas, while the media capture CO_2 and, to a lesser extent, N_2. Once the media have been saturated, they are depressurized, and the CO_2 and N_2 are released into the tail gas stream. A typical PSA system employs multiple vessels operating in different stages of pressurization, depressurization and regeneration. PSA can capture between 95 and 98 percent of the CH_4; the exact percentage will vary depending on the design of the PSA, which is optimized to balance system performance and system economics.

Solvent Scrubbing

Solvent scrubbing processes use a chemical solvent such as amine or a physical solvent like Selexol to strip CO_2 and H_2S from the biogas stream. CO_2 is adsorbed into the solvent, allowing CH_4 to pass through into the RNG product stream. In an amine system, the solution is heated in a separate vessel to release the CO_2 into the tail gas stream; in a Selexol process, the solvent is depressurized, which releases the CO_2. CH_4 capture efficiency varies between 97 and 99 percent for physical solvents but is often greater than 99 percent for amine solvents given that amine solutions are particularly selective for CO_2.

70 U.S. EPA. September 2016. Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies. EPA/600/R-16/099. p. 29. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100QCXZ.PDF?Dockey=P100QCXZ.PDF.

Water Scrubbing

Water scrubbing (sometimes called water wash) is a simple process in which the biogas is pressurized into water. CO_2 is adsorbed into the water while the CH_4 passes through into the RNG product gas stream. The water is then depressurized, and the CO_2 is allowed to pass through in the tail gas. CH_4 capture efficiency of water scrubbing systems is typically greater than 99 percent.

Biogas Flow Rates for CO_2 Removal Technologies

Each CO_2 removal technology allows for a different range of biogas flow rates. Typical flow rates for the four main technologies are summarized in Table 6. Process flow diagrams of the four main types of advanced CO_2 removal technologies (membrane, solvent, PSA, water scrubbing) were presented in a webinar by LMOP Industry Partner DTE Biomass Energy.[71]

Table 6. Typical Flow Rates for Advanced CO_2 Removal Technologies

Technology	Inlet Biogas Flow Range (standard cfm [scfm])
Single-Pass Membrane	50 to 400
Multiple-Pass Membrane	200 to 5,000+
PSA	800 to 5,000+
Solvent Scrubbing	1,000 to 5,000+
Water Scrubbing	50 to 3,000

Additional discussion of primary, secondary and advanced treatment is available in Chapter 3 of the LMOP *LFG Energy Project Development Handbook*.[72]

7.2 VOC/Siloxane Removal Technologies

For any vehicle fuel or pipeline injection project, a critical part of the LFG conditioning process is the removal of VOCs and siloxanes. Even trace amounts of siloxanes can damage engines, turbines and compressors and so must be removed. VOCs are an environmental pollutant that would be sufficiently destroyed in an engine or turbine, but they are similar in molecular structure to siloxanes. This means any medium that is designed to remove siloxanes will also capture VOCs—usually one cannot be removed without capturing the other.

The concentration of siloxanes within biogas can vary widely by source type and the specific site. A 2017 report prepared by the California Biogas Collaborative noted the following ranges by source type for siloxane concentrations in raw biogas: 0 to 400 milligrams per cubic meter (mg/m^3) for WRRFs, 0 to 50 mg/m^3 for landfills and 0 to 0.2 mg/m^3 for livestock farms (no results available for stand-alone MSW digesters).[73] These results indicate that siloxane contamination is a potential issue mainly with WRRF biogas and LFG, primarily because siloxanes are found in many cosmetic, health and beauty products.

---

71 Hill, M.R. November 2017. Upgrading Landfill Gas to Pipeline Quality Natural Gas. https://www.epa.gov/sites/production/files/2017-11/documents/lmop_webinar_november_16_2017.pdf.

72 U.S. EPA. June 2017. LFG Energy Project Development Handbook. https://www.epa.gov/lmop/landfill-gas-energy-project-development-handbook.

73 California Biomass Collaborative. January 2017. Renewable Energy Resource, Technology, and Economic Assessments. Appendix H—Task 8: Comparative Assessment of Technology Options for Biogas Clean-Up. CEC-500-2017-007-APH. https://cwec.ucdavis.edu/wp-content/uploads/03-16-2017-CEC-500-2017-007.pdf.

For projects with smaller gas flows or projects with higher gas flows but relatively low concentrations of VOCs and siloxanes, a non-regenerative carbon medium is typically used to remove the contaminants. Companies that specialize in the removal of these compounds will analyze gas samples and prepare a site-specific carbon medium 'recipe' best suited for removing them. Under normal operation, gas quality is periodically monitored to determine when the medium is saturated and replacement is necessary. These types of media can be disposed of in a landfill, and no other special handling is required.

For higher gas flows or projects with high concentrations of VOCs or siloxanes, a regenerative process is required. As with the non-regenerative systems, a medium is used to capture the contaminants, but instead of disposing of media once saturated, the media are regenerated through a temperature or PSA process. VOCs and siloxanes de-adsorb with a change in pressure or temperature and are directed to a flare for combustion. These flares require pilot gas to fuel the flare, which can be either biogas, propane or fossil natural gas.

7.3 N_2 Removal Technologies

N_2 removal (or rejection) may be required as a part of the biogas conditioning system, depending on the biogas inlet N_2 levels and the required RNG specifications. Because of the potential intrusion of ambient air (which contains N_2) when biogas is collected from landfills, N_2 is typically more of an issue in LFG as compared to biogas from anaerobic digesters. An exception to this can be biogas collected from agricultural waste lagoons with membrane covers, as these systems can also allow air leaks into the gas stream.

N_2 is difficult and expensive to remove from biogas given the similar diameters of N_2 and CH_4 molecules, which are approximately 3.6 angstroms and 3.8 angstroms, respectively.

Nitrogen rejection systems remove N_2 gas from biogas streams via PSA or membranes. The typical RNG conditioning process initially removes trace-level contaminants and most CO_2, while allowing N_2 to pass through the system with the CH_4. A secondary N_2-specific rejection system may be required at the end of the gas conditioning system to remove N_2 to acceptable end use levels. Some biogas conditioning systems remove N_2 concurrently with CO_2 using adsorbents that have a high kinetic selectivity toward N_2 and O_2.

N_2 removal processing can reduce the CH_4 recovery rates—the impact on CH_4 recovery varies depending on the inlet N_2, outlet N_2 specifications and the technology used to remove the N_2. In one example, the CH_4 recovery drops from 90 to 81.5 percent when an N_2 and O_2 removal unit is added to the process.[74]

[74] Smyth, P., and J. Pierce. January 2011. Quantification of the Incremental Cost of Nitrogen and Oxygen Removal at High-Btu Plants. Presented at 14th Annual EPA LMOP Conference and Project Expo. https://www.epa.gov/sites/production/files/2016-06/documents/smyth.pdf.

Many system designers and project developers advocate for reducing the N_2 content at the source, prior to biogas conditioning, as a more cost-effective method of achieving the outlet N_2 specification. There are hardware and software options available to help LFG system operators improve wellfield efficiencies and mitigate cleanup costs. An LMOP 2017 webinar provides information on landfill wellfield design, construction and operational considerations for RNG projects.[75]

LMOP's RNG Flow Rate Estimation Tool[76] can serve as a screening guide to help stakeholders quickly estimate normalized gas flows for LFG-to-RNG projects.

LMOP's RNG Flow Rate Tool calculates the adjusted flow rate and corresponding heat content (Btu) value of LFG after adjusting a wellfield to meet the inlet specifications for RNG treatment/processing technology.

Treatment technologies often specify that the inlet gas must contain N_2 levels lower than what may be typically measured in LFG; adjusting the collection system to achieve N_2 levels may impact the LFG flow rate.

7.4 O_2 Removal Technologies

Many natural gas utilities have strict limits on O_2 for RNG that is injected into a pipeline network. Excessive amounts of O_2 can accelerate pipeline infrastructure corrosion, resulting in many utilities setting the upper limit of allowable O_2 from 0.2 percent to as low as 2 parts per million. For RNG used directly in vehicles, SAE J1616 has no limit for O_2 due to the low water vapor content requirements. CARB's specifications for commercial CNG chemical composition set a 1 percent O_2 upper limit. While it is usually feasible to reduce O_2 in LFG to less than 1 percent through wellfield tuning and improvements, O_2 removal systems are often required for pipeline injection projects on landfills.

Stand-alone O_2 removal systems remove O_2 through a catalytic reactor and typically are the last step in the LFG conditioning process. Biogas is heated and passed over a catalyst bed, where the O_2 reacts with some of the CH_4 to create CO_2 and water. The biogas exiting the reactor is saturated with moisture and must be dehydrated, typically by using a desiccant dryer or temperature swing adsorption process. Other processes involved in the conditioning of LFG, such as membrane separators and PSA, do remove some O_2, which must be considered when designing and sizing a project. Some PSA systems are also effective in removing nearly all O_2.

Due to the added capital and operating costs of incorporating an O_2 removal system, these systems are often found to be cost-prohibitive for projects with an LFG flow rate less than 1,000 scfm. Costs to heat the biogas and remove moisture must also be considered when developing project financials. These systems may negatively impact CH_4 capture efficiency and add CO_2 to the product gas stream as well. The CH_4 loss and CO_2 addition are small, but not negligible.

7.5 The Future of RNG Processing Technologies

There are continuing advancements in RNG processing technologies to improve CH_4 recovery rates, reduce the impacts of elevated N_2 and reduce the energy intensity of each process. Increased selectivity in membrane and PSA systems, along with solvent technology, continue to be developed. These improvements will likely continue as long as there is a strong market for RNG.

75 U.S. EPA. November 2017. Wellfield Operations and Technologies for Upgrading Landfill Gas. https://www.epa.gov/lmop/wellfield-operations-and-technologies-upgrading-landfill-gas. Accessed April 3, 2019.

76 U.S. EPA. January 2020. Renewable Natural Gas Flow Rate Estimation Tool. https://www.epa.gov/lmop/renewable-natural-gas-flow-rate-estimation-tool.

7.6 Reliable Power Sources for Advanced Treatment

Advanced treatment to upgrade biogas into RNG requires a reliable power source. The power can be purchased from the grid or generated on site.

If the electricity market pricing is favorable and enough power service is available at the location of the project, the local electric utility can power the processing plant. Even with reliable power purchased from the grid, some RNG projects have backup emergency generators to power the processing in the case of a power outage.

Some RNG projects also generate power for the production facility on site. If the process is powered with renewable energy such as solar, wind, excess biogas not sent to the RNG processing plant or even residual tail gas from the RNG processing plant, the overall CI of the LFG-to-fuel pathway can be reduced, which could result in additional credits from RNG used for transportation fuel.

The tail gas left over from the upgrading process has a diluted CH_4 content that can typically vary from less than 1 percent to as much as 30 percent. For example, at the Cedar Hills Regional Landfill in Washington, the tail gas from the RNG processing plant is mixed with unconditioned LFG and routed to a series of 300-kilowatt Detroit Diesel engines modified for biogas operation, which generate 4 to 5 megawatts of electricity or approximately 80 percent of the electricity needed to run the plant.[77]

7.7 Compressing RNG

Final compression of the RNG depends on how the gas will be used. For vehicles, final CNG storage compression is around 3,500 pound-force per square inch gauge (psig). If the gas is transported via tube/tank trailer, the compression can be as high as 4,000 psig, while for pipeline injection, the compression varies between 50 to 1,000 psig depending on the interconnect location and the pipeline.[78]

8.0 BARRIERS, POLICY DRIVERS AND INCENTIVES RELATED TO RNG PROJECT DEVELOPMENT

RNG project development faces two main types of barriers: economic and technical. The economics of project development can be challenging to overcome, primarily due to the abundance and prolonged low cost of fossil natural gas. Under current market conditions, it is more expensive to produce RNG from any feedstock than it is to purchase fossil natural gas. This price disparity is often amplified by the challenges and costs associated with pipeline interconnection to move the RNG to end use customers.

On the technical side, upgrading raw biogas to RNG requires meeting numerous gas quality specifications, which can vary by state or pipeline system and can be difficult to achieve cost-effectively depending on the biogas source. Additionally, utilities may have the misconception that RNG is not as clean as, or is somehow lower in quality than, fossil natural gas. The following sections describe the nature of each barrier in detail, with solutions to overcome them.

---

[77] U.S. EPA. March 2020. Landfill and LFG Energy Project Database (LMOP Project IDs 1685-0 and 1685-1). https://www.epa.gov/lmop/landfill-gas-energy-project-data. See also http://www.bioenergy-wa.com/faq/.

[78] American Biogas Council. How to Make RNG/Biomethane. https://americanbiogascouncil.org/resources/how-to-make-rng-biomethane/. Accessed March 28, 2019.

8.1 Economic Barriers

The two main economic barriers to producing RNG are the capital and operating costs associated with capturing and cleaning biogas into RNG, relative to the current low price of fossil natural gas, and the cost of delivering RNG to customers, often by building a pipeline interconnection or investing in equipment to deliver the RNG another way. Because fossil natural gas has been less expensive to produce in recent years, it is difficult for RNG to be cost-effective on a straight economic basis. The cost disparity between RNG and conventional fossil natural gas production can be mitigated by policy or legislation that creates demand for and premium pricing for RNG. In addition, in some cases the cost to capture the biogas can be considered a "sunk" cost because the facility has already put in biogas collection infrastructure apart from the RNG (biogas upgrading) project.

Without a pipeline interconnection, it is often difficult to link an RNG supply to customer demand, which could be local or remote. However, the costs associated with gas cleanup and/or interconnection can be reduced through scale economies from partnerships and shared infrastructure, such as digester clusters that share a single upgrading skid and injection point.

Cost of Processing to RNG Quality

The 2019 average Henry Hub spot price of fossil natural gas was $2.57 per million Btu ($3.17 in 2018 and $2.99 in 2017).[79] At this price, it is impossible for RNG to directly compete with the market price of fossil natural gas (i.e., without environmental attribute value), given the costs associated with capturing biogas and processing it into RNG. A collaborative study published in 2016 determined a cost range of $7 per million Btu (very large-scale) to $25 per million Btu (small-scale) for projects upgrading biogas to RNG for pipeline injection.[80] While state and federal environmental attribute market incentives (i.e., credits) exist, particularly for use as an on-road transportation fuel, the pricing and stability of environmental attributes created under these programs can be volatile. For example, between March 2015 and March 2020, the price of D3 Renewable Identification Numbers (RINs) under the EPA RFS was as low as $0.48 and as high as $2.95.[81] Given this volatility, some financial institutions may be hesitant to accept these credits, or apply a steep discount to the credit value when calculating the potential revenue these environmental attributes may provide to a project.[82] It takes a certain type of investor with a particular risk profile to be comfortable with financing an RNG project. Additional policy mechanisms and voluntary or mandatory markets to create longer-term stability and additional value for RNG's environmental attributes, regardless of how the RNG is ultimately used, would help encourage investment or allow for longer-term purchase agreements, similar to how RPS programs for electricity helped generate longer-term power purchase agreements (PPAs) with premium pricing for electricity projects.

Cost of Pipeline Interconnection

Pipeline interconnection can be a significant barrier to RNG project implementation, particularly when working with local distribution companies. The interconnection equipment, pipeline extensions and an often-lengthy planning process can add costs to the point of making a project uneconomical. In California,

---

79 U.S. EIA. Natural Gas. April 2020. Henry Hub Natural Gas Spot Price. https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm. Accessed April 30, 2020.

80 U.S. EPA. September 2016. Evaluating the Air Quality, Climate & Economic Impacts of Biogas Management Technologies. EPA/600/R-16/099. https://nepis.epa.gov/Exe/ZyPDF.cgi/P100QCXZ.PDF?Dockey=P100QCXZ.PDF.

81 U.S. EPA. RIN Trades and Price Information. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information. Accessed April 29, 2020.

82 M.J. Bradley & Associates. July 2019. Renewable Natural Gas Project Economics. https://www.mjbradley.com/sites/default/files/RNGEconomics07152019.pdf.

for example, interconnection costs average between $1.5 and $3 million per site, depending on facility size and location (see Figure 9).[83] These high costs and long lead times can be challenging for RNG project developers and make projects difficult to finance. In addition, utilities that are required to provide least-cost services to their customers are restricted from taking on these added costs without regulatory approval(s), adding to the complexity.

An impediment to many manure-based and small stand-alone and wastewater digester projects pursuing RNG pipeline injection is the high cost of natural gas utility interconnects as compared to the relatively small quantity of RNG produced per project. However, in recent years, the cost and scale at which biogas cleanup technology can work has been reduced considerably.

Moreover, multiple projects have successfully enabled development and use of a single interconnect (injection point) for aggregating biogas from more than one manure-based digester project. Under this "hub and spoke" model, partially conditioned biogas can be transported to one RNG conditioning and utility interconnect location or multiple RNG gas conditioning facilities can transport RNG fuel via a virtual pipeline with compressed gas tube trailers to a common interconnect location. Each method has been demonstrated in the past few years.

8.2 Technical Barriers

Varying Specifications for RNG Injection

In the United States, hundreds of independent gas systems make up the natural gas pipeline network, and each system has its own requirements. Some of these requirements, such as elevated heating (Btu) values, may effectively prohibit RNG interconnection. For example, a project may not be able to get financing out of concern that the RNG will not consistently meet strict specifications, leading to lost revenue. If pipeline specifications were more standardized, there would be more clarity and certainty for RNG project developers as well as equipment and technology providers.

In California, Southern California Gas Company (SoCalGas) Rule 30 included a minimum heating value of 990 Btu/scf as one of its pipeline requirements. Given the technical and economic challenges of consistently meeting that specification (equivalent to 98 percent CH_4), very few RNG projects were built in California. In fact, more than 95 percent of the RNG earning LCFS credits in 2017 was sourced from out-of-state facilities.[84] SoCalGas undertook extensive testing to evaluate whether any RNG with a lower heating value could be accepted into the pipeline without introducing risk to the pipeline network. Because of the tests, Rule 30 was amended in 2017 to allow the interconnection parties to request a gas quality deviation for lower heating values. However, the California Public Utilities Commission (CPUC) must approve any waiver before the RNG is injected into the pipeline, which adds time and cost to a project.[85]

Treatment Processes

Another potential challenge in developing an RNG project is the quality of the source biogas. While it is technically possible to condition biogas of almost any quality into RNG, systems that can process large flows of biogas at extremely low CH_4 concentrations or with high levels of undesirable constituents (such

---

83 CPUC. June 2015. Decision Regarding the Costs of Compliance with Decision 14-01-034 and Adoption of Biomethane Promotion Policies and Program. Decision 15-06-029. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K572/152572023.PDF.

84 Notes from attending US Biogas 2017 conference.

85 Lucas, J. October 2017. SoCalGas' Interconnection Process, Tools and Improvements. Presented at US Biogas 2017.

as H_2S, VOCs, siloxanes, N_2, or O_2) are difficult to scale down to smaller flow ranges. This can eliminate projects from consideration until the inlet biogas quality can be increased. Non-landfill sources of biogas typically generate lower biogas flows than landfills do, but the biogas is cleaner than LFG (e.g., greater than 60 percent CH_4 and less costly to purify).

For landfills, one of the largest impediments to additional RNG project development is the presence of N_2 in the LFG. N_2 is an inert gas that reduces the heating value of the RNG, and with most gas conditioning technologies it is difficult to remove. Gas conditioning technology or LFG wellfield operational changes that can address these elevated N_2 levels are discussed in Section 7.0.

8.3 Perception of RNG Quality

One common misconception about RNG is that it is of sub-par quality (e.g., has higher contaminant levels) compared to fossil natural gas. Comparisons of constituent concentrations for fossil natural gas and RNG from three types of feedstocks by the Gas Technology Institute show that RNG typically has lower or similar concentrations for pollutants such as CO_2, O_2, H_2S, total sulfur, aromatic hydrocarbons and other VOCs, while RNG typically has higher concentrations of pollutants such as metals, siloxanes and halocarbons.[86] Education can help to inform project stakeholders and the public about RNG and its development while emphasizing the benefits that can be realized from these projects. Several groups have created outreach materials to educate different audiences and to provide technical assistance to stakeholders evaluating RNG projects. For example:

- SoCalGas developed an RNG tool kit that includes the basics of RNG, information on upgrading technologies, gas specifications, interconnection questions, incentives, and other tools and resources. Other than the broad overview materials, most of these resources are specific to California.
- The Coalition for Renewable Natural Gas provides state and federal policy tracking, data for RNG projects, a model pipeline specification and reports.
- The U.S. DOE Alternative Fuels Data Center provides data and tools related to RNG, with an emphasis on vehicle fuel applications.
- Energy Vision has profiled many RNG projects and compiled several reports and fact sheets detailing the environmental, economic and air quality benefits this strategy achieves.

8.4 Policies and Incentives Related to Pipeline Injection

A policy change that can help overcome RNG project development barriers is the establishment of interconnection incentives and flexible, transparent biogas quality guidelines for pipeline injection. Interconnection incentive programs help developers offset the upfront costs of establishing a project. Established yet flexible quality guidelines or standards make it easier for developers to design the proper biogas treatment system for the appropriate amount of upgrading to meet the specifications. Examples of incentive programs and biogas quality standards for pipeline injection are discussed below.

Example: Policies and Incentives in California

California Senate Bill (SB) 1383 directed CARB to implement regulations to reduce CH_4 emissions by 40 percent by 2030 as compared to 2013 levels. Further, given dairy farming's prominent contribution to

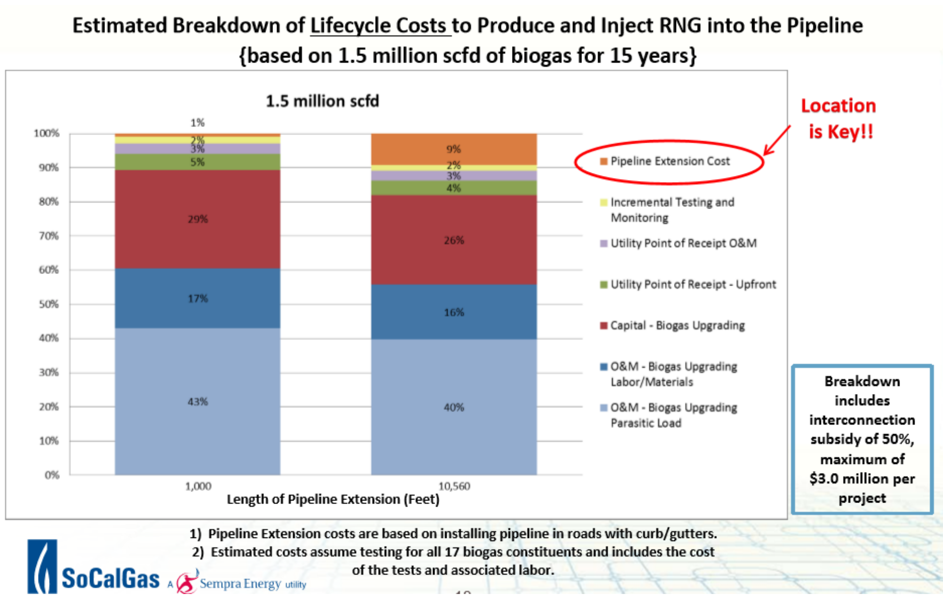
[86] Wiley, Kristine. October 2018. Renewable Natural Gas (RNG): Gas Quality Considerations. Presented at 2018 Natural Gas STAR and Methane Challenge Renewable Natural Gas Workshop. https://www.epa.gov/natural-gas-star-program/2018-natural-gas-star-and-methane-challenge-renewable-natural-gas-workshop.

CH_4 emissions in the state, SB 1383 included provisions directing gas corporations to implement at least five (combined total in the state, not per corporation) dairy-based RNG pipeline injection projects. The bill allows for "reasonable pipeline infrastructure costs" to be recoverable in the rates.[87]

The California biomethane interconnection incentive program has $40 million available to offset interconnection costs through December 31, 2021. The program provides 50 percent of eligible biogas collection and interconnection costs (up to $5 million per project) for cluster (three or more) dairy projects and 50 percent of eligible interconnection costs (up to $3 million per project) for other RNG sources including landfills, WRRFs, stand-alone organic waste digesters and non-cluster (one or two) dairy projects.[88,89]

SoCalGas has estimated the life cycle costs to upgrade biogas into RNG and inject it into the pipeline and analyzed the relative cost of each component to help prospective projects evaluate the major cost drivers in their projects. The cost breakdown in Figure 9 incorporates a $3 million subsidy from the biomethane interconnection incentive program for eligible interconnection costs.[90]

Figure 9. Breakdown of RNG Processing and Interconnection Costs[91]



87 Lucas, J. September 2017. Renewable Natural Gas Projects. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/sites/production/files/2017-10/documents/lucas_rng_2017_panel1.pdf.

88 Lucas, J. September 2017. Renewable Natural Gas Projects. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/sites/production/files/2017-10/documents/lucas_rng_2017_panel1.pdf.

89 California State Assembly. September 2016. AB 2313: Renewable Natural Gas: Monetary Incentive Program for Biomethane Projects: Pipeline Infrastructure. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2313. Accessed April 3, 2019.

90 Lucas, J. September 2017. Renewable Natural Gas Projects. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/sites/production/files/2017-10/documents/lucas_rng_2017_panel1.pdf.

91 Lucas, J. September 2017. Renewable Natural Gas Projects. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/sites/production/files/2017-10/documents/lucas_rng_2017_panel1.pdf. Figure used with permission from Southern California Gas Company.

Example: Policies and Incentives in Washington

On March 22, 2018, the Governor of Washington signed House Bill 2580, "Promoting Renewable Natural Gas."[92] This established a voluntary program that encourages increased production of RNG through tax incentives and tools, including an inventory of potential RNG supply and associated costs. The legislation also directed relevant state agencies and regulatory bodies to establish voluntary gas quality standards for injection of RNG into the natural gas system, and policy recommendations to promote RNG development. The Washington State Department of Commerce and Washington State University's Energy Program, an LMOP State Partner, jointly provided a study to the legislature in December 2018, with an inventory of RNG opportunities and information on economics and policies related to RNG project development within the state.[93]

Example: Gas Quality Standards at a State Level

Illinois set standards in the mid-1980s for transportation of natural gas, including CH_4 from landfills. The gas must meet the standards implemented by the Illinois Commerce Commission before it may be placed into the public utility gas system.[94]

Missouri has historical quality standards for natural gas that are applicable to all gases being furnished by a utility that falls under the jurisdiction of the Missouri Public Service Commission.[95] This standard was established before "RNG" was a common term, but RNG is included because the standard is applicable to all gas distributed in the state.

Example: Gas Quality Standards at the Utility Level

The Coalition for Renewable Natural Gas tracks gas quality specifications for more than 40 major transmission gas pipeline operators in the United States, with links to their tariffs.[96]

Example: Interconnect Guide for RNG in Northeastern States

In September 2019, the Northeast Gas Association and the Gas Technology Institute published a guide to provide a technical framework for introducing RNG into the natural gas distribution pipeline network in parts of the northeastern United States. Although basic criteria had been established for alternative gases including RNG, inconsistent approaches to evaluating acceptance criteria and trace constituent composition had proven to be a barrier to wide-scale acceptance of RNG directly into distribution networks. The guide was written to maximize acceptance of this valuable energy resource, by minimizing technical uncertainty and better quantifying potential risks, without compromising public safety and

---

92 Washington State Legislature. Bill Information: HB 2580—2017-18. https://app.leg.wa.gov/billsummary?BillNumber=2580&Year=2017. Accessed March 27, 2019.

93 Washington State Department of Commerce and Washington State University Energy Program. December 2018. Promoting Renewable Natural Gas in Washington State. http://www.commerce.wa.gov/wp-content/uploads/2019/01/Energy-Promoting-RNG-in-Washington-State.pdf.

94 Illinois Public Utility Commission. 1987. Safety and Quality Standards for Gas Transportation for a Private Energy Entity by Gas Utilities. Section 530.10: Standards. http://www.ilga.gov/commission/jcar/admincode/083/08300530sections.html. Accessed March 27, 2019.

95 Missouri Public Service Commission. 2019. Rules of Department of Economic Development: Division 240—Public Service Commission. Chapter 10—Utilities. Standards of Quality. 4 CSR 240-10.30. https://www.sos.mo.gov/cmsimages/adrules/csr/current/4csr/4c240-10.pdf.

96 Coalition for Renewable Natural Gas. Major Transmission Pipeline Tariffs. http://www.rngcoalition.com/pipeline-database. Accessed April 3, 2019.

facility integrity. The guideline also addresses current challenges to RNG injection through the following objectives:[97]

- Provide a consistent approach for assessing project viability.
- Define requirements to avoid interruption of service.
- Provide a standardized framework to reduce uncertainty and optimize design.
- Outline structure for the RNG development process.
- List roles and responsibilities for each party.

The guideline includes helpful elements such as a process flow diagram, checklists, proposed biogas constituent sampling plans, a list of technical references and a sample interconnect agreement.

8.5 Policies and Incentives Related to Use of RNG as Transportation Fuel

Federal

The federal RFS requires obligated parties to meet a Renewable Volume Obligation based on the amount of petroleum-based fuels they produce or import annually; one way to meet the Renewable Volume Obligation is by obtaining tradeable credits known as RINs, which are issued to producers of renewable fuels. To generate RINs, a fuel must meet one of the EPA-approved pathways. RNG can fall under two different RIN categories based on the biogas source:

- D3, the category for biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; and biogas from the cellulosic components of biomass processed in other waste digesters.

- D5, the category for biogas from waste digesters (e.g., organic fraction of municipal solid waste or food waste).

State-Specific LCFSs

California's LCFS was designed to encourage the use and production of cleaner low-carbon fuels in the state. The LCFS sets CI targets that transportation fuel providers in the state must meet each year. The CI targets decrease over time, which results in a higher percentage of lower CI fuels (e.g., natural gas, RNG, hydrogen, electricity) in the fuel mix. The LCFS parameters are expressed in terms of the CI of gasoline and diesel and the fuels that replace them. A fuel's CI is the measure of GHG emissions associated with producing and consuming it and is based on a complete life cycle analysis. Fuels with CIs lower than the annual standard set by the LCFS generate credits, while fuels with higher CIs generate deficits. The LCFS includes various fuel pathways, including for RNG made from the various feedstocks of anaerobic digester biogas or LFG.[98]

Oregon's Clean Fuels Program seeks to reduce the CI of transportation fuels in Oregon. It functions very similarly to California's LCFS and also includes approved pathways for RNG made from AD biogas or LFG

[97] Northeast Gas Association and Gas Technology Institute. August 2019. Interconnect Guide for Renewable Natural Gas (RNG) in New York State. https://www.northeastgas.org/pdf/nga_gti_interconnect_0919.pdf.

[98] California Low Carbon Fuel Standard, California Code of Regulations, Title 17, Sections 95480–95489; 95491–95497. https://www.arb.ca.gov/regact/2015/lcfs2015/lcfsfinalregorder.pdf.

as the feedstock.[99] The CFP includes standards for gasoline and its fuel substitutes and diesel and its fuel substitutes.

National Ambient Air Quality Standards

Local jurisdictions that are unable to meet EPA-established National Ambient Air Quality Standards must develop strategies to attain the standards, including a timeline to achieve compliance. In urban areas of non-attainment for ozone and PM, transportation-related emission reduction strategies must be part of the solution. Replacing heavy-duty diesel vehicles with natural gas vehicles running on RNG provides near-zero emissions of NO_X and serves as a low-carbon alternative. This can be an important part of the implementation plan for these urban centers to achieve attainment.

Municipal Natural Gas Fleet Conversion

Municipal vehicle fleets—especially transit buses and refuse trucks—are often among the largest fuel consumers in a city. Many U.S. cities have committed to reducing the petroleum dependency of their fleets by replacing their existing fleets with vehicles that run on alternative fuel, including RNG. In 2016, eight major cities (Atlanta, Charlotte, Indianapolis, Orlando, Rochester, Sacramento, San Diego and West Palm Beach) formed the Energy Secure Cities Coalition, with a combined goal of replacing 50,000 petroleum-fueled vehicles with alternative-fueled vehicles by 2025.[100]

In addition to city-owned fleet upgrades, other municipalities have built CNG fleet requirements into their franchise agreements with third-party waste haulers that operate within their jurisdiction to achieve greener fleets. For example, in Seminole County, Florida, two waste haulers that cover approximately 65,000 homes are required to replace their diesel trucks with CNG vehicles by the end of 2020.[101] The EPA Managing and Transforming Waste Streams Tool has sample franchise agreement language for requiring CNG or other alternative fuel vehicles.[102]

8.6 State Regulatory Policies and Incentives Related to Electricity

While power prices have been relatively low and are forecasted to remain low for the foreseeable future, some state RPS programs have renewable energy certificates (RECs) that are favorable to RNG derived from biogas.

In 2018 legislation, California adopted an updated and aggressive RPS under SB 100. The RPS now requires 60 percent renewables-sourced electricity by 2030 and 100 percent carbon-free electricity by 2045. RNG is eligible to generate RECs if certified by the California Energy Commission (CEC) but Assembly Bill 2196

---

99 Oregon Department of Environmental Quality. Fuel Pathways—Carbon Intensity Values. https://www.oregon.gov/deq/ghgp/cfp/Pages/Clean-Fuel-Pathways.aspx. Accessed December 23, 2020.

100 Securing America's Future Energy. March 2016. Eight Major Cities Unite to Form Energy Secure Cities Coalition—Fleets Embracing Alternative Fuels to Improve America's National and Economic Security. https://archive.secureenergy.org/press/eight-major-cities-unite-to-form-energy-secure-cities-coalition-fleets-embracing-alternative-fuels-to-improve-americas-national-and-economic-security/.

101 Comas, M.E. July 2017. Seminole Switching to Natural-Gas Garbage Trucks. Orlando Sentinel. http://www.orlandosentinel.com/news/seminole/os-seminole-county-waste-natural-gas-20170727-story.html.

102 U.S. EPA. Managing and Transforming Waste Streams—A Tool for Communities. https://www.epa.gov/transforming-waste-tool/local-government-clauses-transforming-waste-streams-communities#purchasing. Accessed July 22, 2019.

in 2012 reduced reliance on non-California RNG for the purposes of RPS compliance; this provides additional incentive for potential RNG producers located in California.[103]

California's SB 1122 created the Bioenergy Market Adjusting Tariff, which offers eligible small bioenergy renewable generators the opportunity to export electricity to the state's three large investor-owned utilities through a fixed-price standard contract. Category 1 covers biogas from WRRFs, municipal organic waste diversion, food processing and co-digestion, while category 2 covers dairy and other agricultural bioenergy. This has created an opportunity for smaller biogas projects (less than 3 megawatts) to receive long-term PPAs.[104]

The North Carolina RPS, whose targets are not as aggressive as California's, has an animal waste carve-out that is driving investment in manure-based RNG-to-electricity projects. As a result, these RNG projects can negotiate for long-term PPAs to help utilities achieve the mandated RPS targets. Swine waste carve-outs constituted 0.07 percent of prior year retail sales in 2017, constituted 0.14 percent of prior year retail sales in 2019 and will constitute 0.20 percent of prior year retail sales by 2022.[105] See Section 9.0 for a cluster project example in Missouri that is being used to satisfy North Carolina RPS requirements.

As of April 2020, 30 states, Washington, D.C., and three territories had an RPS for electricity; seven states and one territory had a Renewable Portfolio Goal for electricity; three states had a Clean Energy Standard; and two states had a Clean Energy Goal.[106,107]

8.7 Policies and Incentives Related to Sustainability and Environmental Goals

Limited incentives and policy drivers are currently available to direct thermal end uses of RNG, but some state and local voluntary programs are emerging. Additionally, corporate sustainability goals create demand for RNG, including goals that involve carbon footprint reductions or other types of emission reductions.

More than 20 states are initiating economy-wide GHG targets, setting long-term goals and implementing policies to achieve GHG reductions.[108] As these policies are implemented, they can affect all industries operating in the state, including local distribution companies. As a result, these companies are searching for lower-carbon feedstocks to reduce their carbon footprint.

Much like a consumer would pay to participate in a voluntary green power program at their local electric utility, consumers in Pennsylvania now have an option to purchase a credit for RNG sourced from LFG. The Energy Co-op in Pennsylvania has offered voluntary Renewable Natural Gas Credits in partnership

---

103 Ingram, W. October 2017. Reducing Methane Emissions from California's Wastes. Presented at US Biogas 2017.

104 CPUC. Bioenergy Feed-in Tariff Program (SB 1122). http://www.cpuc.ca.gov/SB_1122/. Accessed March 25, 2019.

105 Payne, T., and B. Gale. September 2017. Roeslein Alternative Energy & Duke Energy—Missouri Swine Waste Green Gas Project. https://www.epa.gov/natural-gas-star-program/duke-energy-rng-green-electricity-livestock-waste-missouri-and-north. Accessed April 3, 2019.

106 NC Clean Energy Technology Center. Database of State Incentives for Renewables & Efficiency. Renewable & Clean Energy Standards (map). http://www.dsireusa.org/resources/detailed-summary-maps/. Accessed March 9, 2020.

107 National Conference of State Legislatures. April 2020. State Renewable Portfolio Standards and Goals. https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx. Accessed June 25, 2020.

108 M.J. Bradley & Associates. April 2017. Renewable Natural Gas. The RNG Opportunity for Natural Gas Utilities. https://mjbradley.com/reports/renewable-natural-gas-rng-opportunity-natural-gas-utilities.

with PECO, the local gas utility, since 2016.[109] Vermont Gas launched a similar program in 2017,[110] and as of 2019, efforts were underway in California, New York and Minnesota. Similarly, FortisBC in Canada has offered a voluntary RNG program since 2011 that allows customers to pay a premium to increase the blend of RNG into their natural gas supply.[111] There are a variety of brokers to help certify that the RNG volume sold through a voluntary utility program matches the quantity of RNG injected into its system. Customers pay a higher gas supply rate depending on their selected RNG percentage.

In March 2019, SoCalGas in California announced a plan to replace 5 percent of its fossil natural gas supply with RNG by 2022 and 20 percent by 2030, as part of the company's vision to be the "cleanest natural gas utility in North America." Toward this goal, SoCalGas filed a request with the CPUC to allow its residential and small commercial/industrial customers the option to purchase RNG. Customers who choose to participate would select from a range of dollar amounts or a percentage of total gas usage (for commercial customers), and their monthly gas bill would have a line item showing the extra cost. A settlement agreement was filed with CPUC in April 2020 which provided some updated functions of this RNG tariff program, and CPUC was expected to make a decision on the program later in 2020.[112,113,114,115]

The Midwest Renewable Energy Tracking System (M-RETS) is a web-based system used by power generators, utilities, marketers and qualified reporting entities to track and retire RECs generated under RPSs and other environmental credit systems. In 2019, M-RETS began adapting its software to meet the needs of emerging voluntary programs for thermal energy credits, which were anticipated based on corporate sustainability goals and commitments. M-RETS launched its platform to track renewable thermal certificates in January 2020.[116]

Many corporations and local governments are developing their own GHG emission inventories and incorporating the results into sustainability plans for reducing their carbon footprints and potentially even becoming carbon neutral. Carbon neutrality is when an emitter reduces its carbon footprint to zero through various measures, including emission reduction projects.[117] One standard that corporations use

---

109 The Energy Co-op. Renewable Natural Gas. https://www.theenergy.coop/services-we-offer/natural-gas/. Accessed March 25, 2019.

110 Vermont Gas. VGS Renewable Natural Gas. https://www.vermontgas.com/renewablenaturalgas/. Accessed July 23, 2019.

111 FortisBC. Renewable Natural Gas. https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas. Accessed March 25, 2019.

112 Sempra Energy. February 2019. SoCalGas Seeks to Offer Renewable Natural Gas to Customers. https://www.sempra.com/socalgas-seeks-offer-renewable-natural-gas-customers. Accessed October 4, 2019.

113 Sempra Energy. March 2019. SoCalGas Announces Vision to Be Cleanest Natural Gas Utility. https://www.sempra.com/newsroom/spotlight-articles/socalgas-announces-vision-be-cleanest-natural-gas-utility. Accessed October 4, 2019.

114 Paulson, L. California Energy Markets. April 2020. SoCal Gas RNG Tariff Filed With CPUC. https://www.newsdata.com/california_energy_markets/regulation_status/socal-gas-rng-tariff-filed-with-cpuc/article_b130e2dc-8664-11ea-8c42-33938bdf0f9b.html. Accessed June 24, 2020.

115 SoCalGas. June 12, 2020. RNG Tariff Overview. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M340/K738/340738713.PDF.

116 U.S. Gain. January 2020. US Gain to provide RNG through new M-RETS RTC platform. Biomass Magazine. http://biomassmagazine.com/articles/16783/us-gain-to-provide-rng-through-new-m-rets-rtc-platform. Accessed February 20, 2020.

117 Natural Capital Partners. CarbonNeutral Protocol. https://www.carbonneutral.com/the-carbonneutral-protocol. Accessed April 15, 2019.

to help determine their carbon footprint is *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard*[118] which categorizes emissions into three areas:

- Scope 1 emissions are direct GHG emissions from sources that are owned or controlled by the company.
- Scope 2 emissions are GHG emissions from the generation of purchased electricity that the company consumes.
- Scope 3 emissions are all other indirect GHG emissions that are a result of the company's activities where the company neither owns nor controls the source (reduction of Scope 3 emissions is considered optional for reaching carbon neutrality).

One avenue to reduce Scope 1 emissions is a "directed biogas" wherein the end user extracts an amount of natural gas from the pipeline that is equivalent to the amount of RNG injected into the pipeline from the project. The exact RNG molecules are not necessarily delivered to the end user, but the same amount of fuel is used.[119]

[118] World Resources Institute and World Business Council for Sustainable Development. The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard. https://ghgprotocol.org/corporate-standard. Accessed April 15, 2019.

[119] Harf, J. June 2018. L'Oréal USA on Why Thermal Energy Is Key to Their Sustainability Goals. https://www.renewablethermal.org/loreal-usa-on-why-thermal-energy-is-key-to-their-sustainability-goals/. Accessed April 15, 2019.

9.0 EXAMPLES

9.1 RNG Projects with Feedstock, Delivery Method and End Use

MSW Landfills

Altamont Landfill—MSW to Vehicle Fuel (LNG)	
Location:	Alameda County, California
RNG Start Year:	2009
Description:	There is only one known currently operating onsite LFG-to-LNG project in the United States, which is at the Altamont Landfill.[120] Since the LNG plant started up in 2009, Waste Management and Linde have displaced 2.5 million gallons of diesel fuel per year by producing up to 13,000 gallons of LNG per day, enough to fuel 300 garbage trucks. The landfill also produces enough electricity from LFG to power the LNG plant and about 8,000 homes per year.[121]

Greentree Landfill—MSW to Pipeline-Injected RNG for Electricity	
Location:	Kersey, Pennsylvania
RNG Start Year:	2007
Description:	The project developed at Greentree Landfill employs membrane, PSA and activated carbon technologies to upgrade approximately 8.4 mmscfd of LFG into RNG (plant capacity is about 15 mmscfd of raw LFG). A dedicated 7-mile pipeline delivers the RNG to the National Fuel Gas interstate pipeline network; the project is expected to produce more than 2 billion cubic feet of RNG per year. Ultimately, through a series of gas sales contracts, the RNG is being used in combined cycle equipment to generate renewable electricity and RECs.[122]

120 U.S. EPA. 2010. Altamont Landfill Gas to Liquefied Natural Gas Project. https://www.epa.gov/lmop/landfill-gas-energy-project-data#altamont. Accessed April 1, 2019.

121 Waste Management, "Case Study: Altamont Landfill and Resource Recovery Facility". https://www.wm.com/documents/pdfs-for-services-section/Case-studies-municipal/PSS_CsStdyAltamLndfllREVISE_rFjjg.pdf.

122 2007 EPA LMOP Project of the Year Award Application. Greentree High Btu Landfill Gas Project. November 2007.

Rodefeld Landfill—MSW and Manure to Pipeline-Injected RNG to Vehicle Fuel	
Location:	Madison, Wisconsin
RNG Start Year:	2011/2019
Description:	Dane County, Wisconsin, has been creating vehicle fuel from LFG on site since 2011 (and generating electricity before that), but completed a new project in 2019 to inject RNG into ANR-TransCanada's natural gas interstate transmission pipeline for use at regional CNG fueling stations. As part of this effort, the County built an off-loading station to allow other biogas plants (including manure-based AD facilities) in the area that convert their gas into RNG to truck their RNG to this station (for a small fee) to tap into the pipeline connection. The project is expected to displace at least 3 million gallons of fossil fuels during the first 12 months of operation.[123]

St. Landry Parish Landfill—MSW to Vehicle Fuel (CNG)	
Location:	St. Landry Parish, Louisiana
RNG Start Year:	2012
Description:	St. Landry Parish, in conjunction with BioCNG, developed a multiphase onsite LFG conditioning and CNG fueling system and an offsite virtual pipeline RNG station. The initial project phase started in 2012, processing 50 scfm of LFG to produce up to 210 GGE of CNG per day for the Parish's use. About three years later, the Parish entered into an agreement with a private waste hauler to fuel its fleet of refuse hauling trucks and constructed a 100-cfm gas conditioning system that produced an additional 420 GGE of vehicle fuel. The Parish added a tube trailer filling system at the landfill, and constructed an offsite RNG trailer off-loading decant panel and a CNG fueling station with natural gas back-up.[124,125]

123 Voegele, E. May 2019. Dane County, Wisconsin, celebrates the opening of RNG project. http://biomassmagazine.com/articles/16126/dane-county-wisconsin-celebrates-the-opening-of-rng-project. Accessed July 22, 2019.

124 Tetra Tech. St. Landry Parish Landfill Biogas Expansion Project, Louisiana. http://www.tetratech.com/en/projects/st-landry-parish-landfill-biogas-expansion-project-louisiana. Accessed March 28, 2019.

125 Wittmann, S. May 2016. Not Stopping at First. Renewable Energy From Waste (May/June). http://www.unisonsolutions.com/wp-content/uploads/2016/07/St-Landry_REWmag-May-June-2016.pdf.

Municipal WRRFs

Janesville WRRF—Sewage Sludge to Vehicle Fuel (CNG)	
Location:	Janesville, Wisconsin
RNG Start Year:	2012
Description:	Janesville has the first community-scale WRRF in the country to fuel public fleet vehicles with CNG produced from biogas on site. [126] The city has digested biosolids since 1970 and generated electricity from biogas since 1985.[127] In 2010, the WRRF began implementing upgrades to further treat a portion of the biogas and also start co-digesting industrial organic wastes. In June 2012, the city began fueling about 10 CNG municipal vehicles with plans to increase that number to 40 vehicles in the future.[128] The WRRF processes about 18 MGD of wastewater, generates 140 cfm of biogas (of which 50 cfm is used to create CNG) at 62 percent CH_4, and has a maximum fuel production capacity of 275 GGE per day.[129]

Newtown Creek WRRF—Sewage Sludge to Pipeline-Injected RNG	
Location:	New York City, New York
RNG Start Year:	2020 (expected)
Description:	The Newtown Creek WRRF is the largest WRRF in New York City, treating up to 310 million gallons of wastewater on an average day and producing more than 500 million cubic feet of biogas per year from eight digesters that together can hold a total of 24 million gallons of sludge.[130] About 40 percent of the biogas is used in boilers to provide heat for the digesters and other buildings, with the remaining 60 percent being flared. Since at least 2014, the city has been exploring the use of excess biogas to create RNG,[131] and as of March 2019, plans were underway to inject RNG into the National Grid pipeline distribution system for residential and commercial consumption.[132] The facility is anticipated to provide enough RNG to heat 2,500 homes and may co-digest an organic slurry from food waste to boost biogas production.[133]

---

126 Energy Vision. 2013. Turning Waste into Vehicle Fuel: Renewable Natural Gas (RNG). A Step-by-Step Guide for Communities. https://energy-vision.org/ev-publications/EV-RNG-Community-Guide.pdf.

127 U.S. DOE Midwest CHP Technical Assistance Partnership. Janesville Wastewater Treatment Plant. https://chptap.lbl.gov/profile/109/JanesvilleWWT-Project_Profile.pdf.

128 Energy Vision. 2013. Turning Waste into Vehicle Fuel: Renewable Natural Gas (RNG). A Step-by-Step Guide for Communities. https://energy-vision.org/ev-publications/EV-RNG-Community-Guide.pdf.

129 BioCNG. Fact Sheet: City of Janesville Wastewater Treatment Plant. http://biocng.us/wp-content/uploads/2015/06/Janesville-Fact-Sheet-2015.pdf.

130 Siegel, N. January 2018. October Tour Recap: Newtown Creek Wastewater Treatment Plant. GreenHomeNYC. https://greenhomenyc.org/blog/october-tour-recap-newtown-creek-wastewater-treatment-plant/. Accessed April 1, 2019.

131 NYC Environmental Protection. December 2013. City Announces Innovative New Partnerships That Will Reduce the Amount of Organic Waste Sent to Landfills, Produce a Reliable Source of Clean Energy and Improve Air Quality. https://www1.nyc.gov/html/dep/html/press_releases/13-121pr.shtml#.XKJaTqR7lEZ. Accessed April 1, 2019.

132 Neighbour, D., and G. Zwicker. March 2019. What China Can Learn from New York City about Wastewater Management. Scientific American. https://blogs.scientificamerican.com/observations/what-china-can-learn-from-new-york-city-about-wastewater-management/. Accessed April 1, 2019.

133 Chahbazpour, D. September 2017. National Grid—Newtown Creek Renewable Gas Demonstration. Presented at EPA Technology Transfer Workshop: Renewable Natural Gas—Driving Value for Natural Gas and Biogas Sectors. https://www.epa.gov/natural-gas-star-program/renewable-natural-gas-driving-value-natural-gas-and-biogas-sectors-workshop.

Point Loma WRRF—Sewage Sludge to Pipeline-Injected RNG for Electricity	
Location:	San Diego, California
RNG Start Year:	2012
Description:	BioFuels Energy, LLC, financed, built and operates the RNG production facility at the Point Loma Wastewater Treatment Facility. The facility can process up to 1.6 mmscfd of biogas generated from eight digesters. [134] BioFuels Energy cleans the biogas to San Diego Gas & Electric's pipeline gas specifications, and after injection into the pipeline system, the RNG is "directed" to fuel cells at two customers: University of California–San Diego (2.8 megawatts) and City of San Diego South Bay Water Reclamation Plant (1.4 megawatts).[135] This process uses existing pipelines and increases the options for biogas usage. This project was the first in California to inject RNG into a natural gas pipeline.[136]

San Antonio Water System (SAWS)—Sewage Sludge to Pipeline-Injected RNG	
Location:	Bexar County, Texas
RNG Start Year:	2010
Description:	SAWS partnered with Ameresco to produce biogas by adding a new biosolids AD process to its facility. In 2010, Ameresco began processing more than 1.5 mmscfd of biogas at 60 percent CH_4 to deliver at least 900,000 cubic feet of RNG per day to a nearby fossil natural gas pipeline for sale on the open market. In addition to offsetting the use of fossil natural gas, SAWS receives approximately $200,000 in royalties annually from the sale of the biogas, which helps keep its rates reasonable.[137,138]

134 BioFuels Energy, LLC. Projects. Biogas Projects. https://biofuelsenergyllc.com/projects. Accessed March 13, 2020.

135 Mazanec, F.. BioFuels Energy, LLC. October 2016. Turning Waste Into Renewable Natural Gas: Point Loma Wastewater Treatment Plant Case Study—Five Years After Commercial Operation. https://www.socalgas.com/1443740098116/Biogas-to-RNG-at-Point-Loma-Wastewater-Treatment-Facility.pdf.

136 Argonne National Laboratory. August 2017. Waste-to-Fuel: A Case Study of Converting Food Waste to Renewable Natural Gas as a Transportation Fuel. ANL/ESD-17/9. https://afdc.energy.gov/files/u/publication/waste_to_fuel.pdf.

137 San Antonio Water System. Biogas. https://www.saws.org/your-water/water-recycling/biogas/. Accessed March 13, 2020.

138 Ameresco. 2017. Case Study: San Antonio Water System, TX. http://www.ameresco.com/wp-content/uploads/2017/11/san-antonio-water-system-tx.pdf.

Livestock Farms

Hilarides Dairy—Manure to Vehicle Fuel (CNG)	
Location:	Tulare County, California
RNG Start Year:	2009
Description:	Hilarides Dairy is a family-run dairy that has been digesting manure from more than 9,000 cows in a covered lagoon digester since December 2004.[139] Part of the 226,000 cubic feet of biogas produced per day in 2017 produced CNG to fuel two heavy-duty milk trucks and six on-farm pickup trucks, displacing 230,000 gallons of diesel annually.[140] When Hilarides began cleaning and compressing its biogas for vehicle fuel in early 2009, it became the first dairy in the United States to do so. The dairy also continues to generate electricity from about two-thirds of the generated biogas.[141,142]

Roeslein Cluster Project—Manure to Pipeline-Injected RNG to Electricity and Vehicle Fuel	
Location:	Missouri
RNG Start Year:	2016
Description:	The North Carolina RPS includes a carve-out for renewable energy from animal waste (poultry and swine), and a utility can meet a portion of the targets through out-of-state purchases. Duke Energy opted to incorporate RNG from manure-based digesters in Missouri to meet its North Carolina RPS obligations, agreeing to purchase one-third of the RNG from a cluster project of nine farms through a 10-year PPA. Roeslein Alternative Energy's RNG production will be built out in phases through 2020; three of the farms were producing RNG as of 2018. The Ruckman Farm began processing 1,350 cfm of biogas using a PSA system in June 2016, injecting the RNG into the American Natural Resources gas pipeline. Locust Ridge Farm and Valley View Farm use membrane systems to process about 400 scfm of biogas each and truck their RNG via a virtual pipeline to the interconnection point at Ruckman Farm. One of Duke's combined cycle power plants in the Southeast pulls the appropriate amount of gas from the local pipeline to generate electricity. Beyond its obligations to Duke, this project also sells excess RNG into the vehicle fuel market.[143,144,145]

139 Western United Resource Development, Inc. December 2006. Prepared for CEC. PIER Final Project Report. Dairy Power Production Program: Dairy Methane Digester System, 90-Day Evaluation Report—Hilarides Dairy. Formerly available at https://www.energy.ca.gov/2006publications/CEC-500-2006-086/CEC-500-2006-086.PDF.

140 Elger, N. April 2017. Innovative Business Models for On-farm Anaerobic Digestion. Presented at Waste to Worth 2017. https://www.epa.gov/sites/production/files/2017-05/documents/innovative-business-models-w2w-2017.pdf.

141 Elmore, C. March 2009. Alternative Fuels: Got Methane? OEM Off-Highway. https://www.oemoffhighway.com/trends/hybrids/article/10166466/alternative-fuels-got-methane. Accessed March 28, 2019.

142 Richardson, L. April 2009. 'Cow-Powered' Milk Truck Debuts. www.CaliforniaFarmer.com (April). http://www.suscon.org/pdfs/news/pdfs/200904_CaliforniaFarmer_Cow-PoweredMilkTruckDebuts.pdf.

143 Payne, T., and B. Gale. September 2017. Roeslein Alternative Energy & Duke Energy—Missouri Swine Waste Green Gas Project. https://www.epa.gov/natural-gas-star-program/duke-energy-rng-green-electricity-livestock-waste-missouri-and-north. Accessed April 3, 2019.

144 Fletcher, K. August 2016. Roeslein Alternative Energy's WTE Project Begins RNG Production. Biomass Magazine. http://biomassmagazine.com/articles/13624/roeslein-alternative-energys-wte-project-begins-rng-production. Accessed April 3, 2019.

145 Scherer, R. August 2017. Regional Biogas Project Advancing. News-Press Now. http://www.newspressnow.com/news/business/regional-biogas-project-advancing/article_1d8b3ab2-c99b-52ba-8445-4aca371639ef.html. Accessed April 3, 2019.

Stand-Alone Organic Waste Management Operations

Blue Line Biogenic CNG Facility—Organic Waste to Vehicle Fuel (CNG)	
Location:	South San Francisco, California
RNG Start Year:	2014
Description:	South San Francisco Scavenger Company (SSFSC) and Blue Line Transfer developed this dry AD system with eight modular AD tunnels and a total processing capacity of 11,200 tons per year. The green waste and food waste feedstocks are collected from commercial and residential (approximately 20,000 households) customers. The project is producing between 380 and 500 diesel gallon equivalents of RNG per day, which fuel 34 CNG vehicles owned by SSFSC. The trucks are filled every weeknight using a slow fill system that provides a mix of CNG from RNG and fossil natural gas, but on weekends the trucks receive renewable CNG only. SSFSC is selling D5 RINs and carbon credits under California's LCFS.[146,147]

CR&R AD Facility—Organic Waste to Pipeline-Injected RNG for Vehicle Fuel (CNG)	
Location:	Perris, California
RNG Start Year:	2016
Description:	CR&R Environmental Services' AD project uses residential and commercial green (yard) and food waste feedstocks, with an initial maximum capacity of 83,600 tons per year (three more phases will follow at a capacity of 83,600 tons each). The system was designed to also accept other types of organic waste including solid and liquid food waste.[148] At full build-out, the facility will be able to convert about 334,000 tons of waste per year into 4 million diesel gallon equivalents of RNG and 250,000 tons of fertilizer.[149] In 2017, the biogas produced was cleaned and compressed into CNG for use by 75 CR&R refuse trucks, but in 2018 CR&R began injecting all the RNG into the SoCalGas fossil natural gas system via a newly built 1.4-mile pipeline, becoming the first RNG project in California to do so. CR&R now pulls the RNG back out of the pipeline to compress it for its vehicles. [150,151] In late 2018, the facility's LCFS application was approved with its requested CI.[152]

---

146 Goldstein, N. May 2018. Facilitating Food Waste Digestion. BioCycle 59(4): 32. https://www.biocycle.net/2018/05/01/facilitating-food-waste-digestion/. Accessed October 2, 2019.

147 Goldstein, N. July 2016. Biogas to Fleet Fuel in South San Francisco. BioCycle 57(6): 35. https://www.biocycle.net/2016/07/14/biogas-fleet-fuel-south-san-francisco/. Accessed October 2, 2019.

148 Goldstein, N. May 2017. High Solids Digester Services California Municipalities. BioCycle 58(4): 44. https://www.biocycle.net/2017/05/01/high-solids-digester-services-california-municipalities/. Accessed April 3, 2019.

149 Pauley, C. November 2018. CR&R Anaerobic Digestion Facility: Renewable Fuel from Organic Waste Recycling. Presented at CBA Symposium—Sacramento. https://www.epa.gov/sites/production/files/2017-11/documents/cba2017-crr_anaerobic_digestion_facitilty.pdf.

150 Goldstein, N. May 2017. High Solids Digester Services California Municipalities. BioCycle 58(4): 44. https://www.biocycle.net/2017/05/01/high-solids-digester-services-california-municipalities/. Accessed April 3, 2019.

151 Waste360 Staff. July 2018. RNG Produced in California by CR&R Flows into SoCalGas Pipelines for the First Time. Waste360. https://www.waste360.com/gas-energy/rng-produced-california-crr-flows-socalgas-pipelines-first-time. Accessed April 3, 2019.

152 BioCycle. February 2019. Anaerobic Digest. BioCycle 60(2): 14. https://www.biocycle.net/2019/02/01/anaerobic-digest-91/. Accessed April 3, 2019.

9.2 Corporate Alternative Fuel Fleets

Corporate sustainability goals are also driving a shift from diesel-based fleets to natural gas-based fleets.

Waste Management, Inc.—CNG and LNG

Waste Management has set a goal to reduce fleet emissions by 45 percent by 2038, as compared to a 2010 baseline, by transitioning 90 percent of its fleet from diesel to alternative fuel vehicles. At the end of 2017, Waste Management had more than 32,000 fleet vehicles overall, including more than 6,500 running on some form of natural gas and 33 percent of those natural gas vehicles fueled by an RNG source. All of the company's fleet operating in California, Oregon and Washington runs on RNG-sourced fuel.[153] Two examples of Waste Management-owned landfills that produce RNG vehicle fuel are the Altamont Landfill (California), with a renewable LNG facility that fueled 170 of the company's waste trucks in 2017, and the Outer Loop Landfill (Kentucky), which produces enough CNG to fuel approximately 800 vehicles.[154]

United Parcel Service (UPS)—CNG and LNG

UPS has 51 natural gas fueling stations across the country (including six new CNG stations in 2017) and a fleet of more than 5,200 natural gas vehicles (including 450 purchased during 2017). During 2017, UPS used more than 15 million gallons of vehicle fuel from RNG in its fleet, an increase from 4.6 million gallons in 2016. In the same year, UPS signed two new agreements to purchase 1.5 million gallons of RNG per year from Fair Oaks Dairy in Indiana and 10 million gallons of RNG per year from Big Ox Energy, based in Wisconsin.[155,156] In 2019, UPS announced the company will purchase a total of 170 million gallon equivalents of RNG from Clean Energy Fuels Corp. through 2026 for use at 18 of its stations in 12 states. This decision is part of UPS' goal to have alternative fuel make up 40 percent of its total ground fuel purchases by 2025 and reduce its ground fleet's GHG emissions by 12 percent by 2025.[157]

153 Waste Management. 2018. Driving Change. 2018 Sustainability Report. http://www.wm.com/sustainability/pdfs/WasteManagement_SustainabilityReport_2018.pdf.

154 U.S. EPA. March 2020. Landfill and LFG Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.

155 UPS. Environmental Responsibility: Fuels & Fleets. https://sustainability.ups.com/fuels-and-fleets/. Accessed April 3, 2019.

156 UPS. November 2017. UPS Increases Use of RNG Through Agreement with Big Ox Energy. Biomass Magazine. http://biomassmagazine.com/articles/14862/ups-increases-use-of-rng-through-agreement-with-big-ox-energy. Accessed April 3, 2019.

157 UPS. May 2019. UPS Makes Largest Purchase of Renewable Natural Gas Ever in the U.S. GlobeNewswire. https://www.globenewswire.com/news-release/2019/05/22/1840772/0/en/UPS-Makes-Largest-Purchase-Of-Renewable-Natural-Gas-Ever-In-The-U-S.html. Accessed July 23, 2019.

LMM-R-4

10.0 RESOURCES

Hyperlinked Resource	Organization
Alternative Fuels Data Center	U.S. DOE
AD webpage	U.S. EPA
AD Facilities Processing Food Waste in the United States: Survey Results	U.S. EPA
Biogas Toolkit	U.S. EPA
Gas Quality Database (information from major transmission pipeline tariffs)	The Coalition for Renewable Natural Gas
Interconnect Guide for RNG in New York State	Northeast Gas Association; Gas Technology Institute
Landfill and LFG Energy Project Database	U.S. EPA LMOP
LFG Energy Project Development Handbook	U.S. EPA LMOP
Livestock Anaerobic Digester Database	U.S. EPA AgSTAR
Managing and Transforming Waste Streams: A Tool for Communities	U.S. EPA
Renewable thermal credit tracking system	M-RETS
RIN Calculator	American Biogas Council
RNG Database	Argonne National Laboratory
RNG Flow Rate Estimation Tool	U.S. EPA LMOP
RNG Project Map	U.S. EPA LMOP / AgSTAR
RNG Tool Kit	SoCalGas
RNG webpage	U.S. EPA LMOP
WRRF “phase 1” database	Water Environment Federation

11.0 ABBREVIATIONS, ACRONYMS AND UNITS OF MEASURE

AD	anaerobic digestion
AFLEET	Alternative Fuel Life-Cycle Environmental and Economic Transportation
Btu	British thermal unit
CARB	California Air Resources Board
CEC	California Energy Commission
cfm	cubic feet per minute
CH_4	methane
CI	carbon intensity
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
g CO_2e/MJ	grams of CO_2 equivalent per megajoule
GGE	gasoline gallon equivalents
GHG	greenhouse gas
H_2S	hydrogen sulfide
LCFS	Low Carbon Fuel Standard
LFG	landfill gas
LMOP	U.S. EPA Landfill Methane Outreach Program
LNG	liquefied natural gas
M-RETS	Midwest Renewable Energy Tracking System
mg/m^3	milligrams per cubic meter
MGD	million gallons per day
mmscfd	million standard cubic feet per day
MSW	municipal solid waste
N_2	nitrogen
NO_X	nitrogen oxide

O_2	oxygen
PM	particulate matter
PPA	power purchase agreement
PSA	pressure swing adsorption
psig	pound-force per square inch gauge
REC	renewable energy certificate
RIN	Renewable Identification Number
RFS	Renewable Fuel Standard
RNG	renewable natural gas
RPS	Renewable Portfolio Standard
SAE J1616	Society of Automotive Engineers *Surface Vehicle Recommended Practice J1616™ for Compressed Natural Gas Vehicle Fuel*
SAWS	San Antonio Water System
SB	Senate bill
scf	standard cubic foot
scfm	standard cubic feet per minute
SoCalGas	Southern California Gas Company
SO_X	sulfur dioxide
SSFSC	South San Francisco Scavenger Company
UPS	United Parcel Service
VOC	volatile organic compound
WEF	Water Environment Federation
WRRF	water resource recovery facility

Appendix A: Natural Gas Companies Accepting RNG into Pipelines

Company Name and Website	State(s) where RNG is Injected	Feedstock(s)[1]	Company Information about RNG	Company's Pipeline Interconnection Standard / Tariff / Similar
Ameren Illinois	Illinois	LF, OW		
ANR Pipeline Company	Missouri, Wisconsin	Ag, LF		TransCanada Biogas Interconnect Facility Requirements
Arkansas Oklahoma Gas Corporation	Arkansas	LF		
Atmos Energy Corporation	Louisiana, Texas	LF	Atmos Energy Environment page	Atmos Energy Utility Operations page
Black Hills Corporation	Iowa, Nebraska	LF, WW		
CenterPoint Energy	Texas	LF	CenterPoint Energy Natural Gas Innovation Act	CenterPoint Energy Rates & Tariffs
Columbia Gas of Ohio, Inc.	Ohio	LF, OW		Columbia Gas of Ohio Regulatory Information
Consumers Energy	Michigan	LF		Consumers Energy Gas Standard Customer Forms
Dominion Energy Ohio	Ohio	LF	Dominion Energy Renewable Natural Gas page	Dominion Energy Ohio Tariff Information
Dominion Energy Questar Pipeline	Utah	WW		Dominion Energy Questar Pipeline FERC Gas Tariff
Dominion Energy Transmission, Inc.	Ohio	LF		Dominion Energy Transmission FERC Gas Tariff
DTE Energy	Michigan	LF	DTE BioGreenGas	Michigan Public Service Commission - Natural Gas Rate Books
Duke Energy	Ohio	LF		Duke Energy Ohio Gas Tariff
East Tennessee Natural Gas	Tennessee	LF	Enbridge Gas RNG page	East Tennessee Natural Gas Tariff
Enable Midstream Partners	Louisiana	LF		Enable Gas Transmission, LLC (EGT) website

Appendix A: Natural Gas Companies Accepting RNG into Pipelines

Company Name and Website	State(s) where RNG is Injected	Feedstock(s)[1]	Company Information about RNG	Company's Pipeline Interconnection Standard / Tariff / Similar
Enterprise Pipeline	Texas	LF		
Equitrans Midstream	Pennsylvania	LF		Equitrans, L.P. FERC Gas Tariff
Four-S Oil Company	Texas	LF		
Fremont Department of Utilities Gas Distribution	Nebraska	WW		
General Gas Pipeline, LLC	Tennessee	LF		
Great Lakes Gas Transmission Company	Michigan	LF		Great Lakes Gas Transmission Tariff
Gulf South Pipeline	Louisiana, Texas	LF		Gulf South Pipeline Company Tariff
Hawaii Gas Transmission and Distribution	Hawaii	WW	Hawaii Gas RNG page	
Houston Pipe Line Company	Texas	LF		Houston Pipe Line Company Gas Quality Specifications
Kinder Morgan	Arizona, Mississippi, Oklahoma, Texas	LF, WW		Kinder Morgan Tariffs page
Memphis Light, Gas and Water (MLGW)	Tennessee	LF		
Metropolitan Utilities District of Omaha	Nebraska	LF		
Montana-Dakota Utilities Co.	Montana	LF		Montana-Dakota Utilities - Rates and Tariffs
Mountaineer Gas Company	West Virginia	LF		Mountaineer Gas Company - Rates and Tariffs
National Fuel Gas	Pennsylvania	LF	National Fuel Gas Distribution Corporation Gas Transportation Operating Procedures Manual	National Fuel PA Regulatory, Tariff and GTOP

Appendix A: Natural Gas Companies Accepting RNG into Pipelines

Company Name and Website	State(s) where RNG is Injected	Feedstock(s)[1]	Company Information about RNG	Company's Pipeline Interconnection Standard / Tariff / Similar
National Gas & Oil Cooperative	Ohio	WW		
National Grid	New York	LF, WW	Renewable Gas - Vision for a Sustainable Gas Network	National Grid - Service Rates
Northern Indiana Public Service Company (NIPSCO)	Indiana	Ag		NIPSCO Rate for Gas Service Renewable Gas Balancing Service
Northern Natural Gas	Kansas, Nebraska, Wisconsin	Ag, WW		Northern Natural Gas Tariff page
NW Natural	Oregon	WW	NW Natural RNG page	NW Natural Oregon Tariff Book
Pacific Gas and Electric Company (PG&E)	California	Ag	PG&E Interconnecting biomethane suppply page	PG&E Tariffs page
Panhandle Eastern Pipe Line Company	Kansas	LF		Panhandle Eastern Pipe Line Company FERC NGA Gas Tariff page
Peoples Natural Gas	Pennsylvania	LF	Peoples Producers, Suppliers & Gas Supply page	Peoples Gas Quality Quick Reference Guide
Philadelphia Gas Works	National	LF		
Piedmont Natural Gas Company, Inc.	North Carolina	Ag		Piedmont Natural Gas Index of Tariff & Service Regulations
Puget Sound Energy	Washington	LF, WW		Puget Sound Energy Natural gas tariffs & rules page
Southern California Gas Company (SoCalGas)	California	Ag, OW, WW	SoCalGas Renewable Gas page	SoCalGas Rule No. 30 Transportation of Customer-Owned Gas
Southern Company Gas	Georgia	LF		
Southern Company Gas (Atlanta Gas Light Company)	Georgia	LF		Atlanta Gas Light Company Tariff
Southern Star Central Gas Pipeline	Kansas, Oklahoma	LF		FERC Gas Tariff of Southern Star Central Gas Pipeline, Inc.

Appendix A: Natural Gas Companies Accepting RNG into Pipelines

Company Name and Website	State(s) where RNG is Injected	Feedstock(s)[1]	Company Information about RNG	Company's Pipeline Interconnection Standard / Tariff / Similar
Summit Utilities, Inc.	Maine	Ag	Summit Announces RNG Initiative - May 2019	
Texas Gas Transmission LLC	Kentucky	LF		Texas Gas Transmission, LLC Tariff
UGI Utilities	Pennsylvania	LF		UGI Tariffs
Utica Gas Services (subsidiary of Williams Gas Pipeline)	Ohio	LF		
Vectren Energy Delivery	Ohio	LF		Vectren Rates & tariffs page
Vermont Gas	Iowa, Quebec, Vermont	Ag, LF, WW	VGS Renewable Natural Gas page	
Williams Gas Pipeline	Washington	LF		Transcontinental Gas Pipe Line Company, LLC FERC Gas Tariff
Wisconsin Public Service Corporation	Wisconsin	OW		
Xcel Energy	Colorado	WW		
XTO Energy	Oklahoma	LF		

Main Sources of Data for Inclusion of Utilities in this List

- U.S. EPA. March 2020. Landfill and LFG Energy Project Database. https://www.epa.gov/lmop/landfill-gas-energy-project-data.
- U.S. EPA. March 2020. Livestock Anaerobic Digester Database. https://www.epa.gov/agstar/livestock-anaerobic-digester-database.
- Mintz, M., P. Vos, M. Tomich, and A. Blumenthal. October 2019. Database of Renewable Natural Gas (RNG) Projects: 2019 Update. Argonne National Laboratory. https://www.anl.gov/es/reference/renewable-natural-gas-database.

1. **Feedstock(s) of the RNG Injected**

Ag	biogas from agricultural digester (may co-digest organic waste)
LF	landfill gas
WW	biogas from wastewater digester (may co-digest organic waste)
OW	biogas from organic waste digester (food waste and/or other organic waste types)