Proposed Rule 1179.1

NOx Emission Reductions from Combustion Equipment at Publicly Owned Treatment Works Facilities

Working Group Meeting #3

Date: November 6, 2019

Conference call #: 1-866-705-2554

Passcode: 185381

Agenda

- Summary of Previous Working Group meeting
- Public Comments
- Applicability
- BARCT Assessment

Photo courtesy of sites.google.com/site/sed695b4/projects/fieldwork/hyperion-treatment-plant

Summary of Last Working Group Meeting

- Approach for biogas rules
- Proposed applicability
  - Boilers, turbines, and microturbines located at POTWs that fire either natural gas and/or digester gas
  - Still assessing the inclusion of engines
  - Other equipment to be subject to a rule with a recent or near future BARCT assessment
- BARCT assessment
  - Rule limits, permit limits, source test results for digester gas equipment in South Coast AQMD and other air districts

Comments Made at Working Group Meeting #2 Source Test Results from San Joaquin Valley

- Stakeholders commented that source tests results for a San Joaquin Valley digester gas boiler may be low because SJVAPCD allows tuning prior to source testing
  - SJVAPCD requires source tests under normal operating conditions
  - Unit must be operating at least 2 hours subsequent to tuning*
  - Rule 1146 requires
    - Emissions testing conducted in as-found operating condition – normal operating conditions
    - Unit must be operating at least 250 hours or 30 days subsequent to the tuning or servicing
  - Despite differing source testing protocols, source tests for boilers in the South Coast Air District and San Joaquin Valley Air District have similar results for digester gas boilers

* Based on conversation with SJVAPCD staff

Comments Made at Working Group Meeting #2
Digester Gas and Ultra-Low NOx Burners

- Stakeholders commented that ultra-low NOx burners are very sensitive to digester gas leading to unstable NOx emission levels
  - A technology assessment will be conducted which will focus on feasibility and understanding the challenges with digester gas
  - Staff has been communicating with burner manufacturers and will continue to gather information
  - Encourage stakeholders to provide information

Comments Made at Working Group Meeting #2
Food Waste Processing

- Stakeholders also commented about Proposed Rule 1179.1 and its applicability to food waste processing
  - Staff has visited several facilities, some of which have plans to receive food waste in the future
  - Staff will evaluate any unique considerations for these facilities
  - Encourage stakeholders to provide information

Applicability

Engines

- If engines are included, staff proposes to copy the provisions and limits for biogas engines from Rule 1110.2 into PR 1179.1
  - Rule 1110.2 has a provision that exempts digester engines from Rule 1110.2 if a Regulation XI rule applicable to digester gas engines is amended/adopted
  - New submittals and application fees will be required for equipment permits, I&M plans, and Title V permit revisions to update references from Rule 1110.2 to PR 1179.1 and respective requirements
- Staff will survey each POTW facility to gather the consensus of including engines in PR 1179.1 applicability
  - Facilities may have different financial constraints

Engines *(continued)*

Current Fiscal Year Permit Application Processing Fees		
Change	Non-Title V	Title V
Engine Permit (per equipment)	$962.75 - $4,319.40*	$1,206.41 - $5,412.63*
I & M Plan (per plan/per facility)	$725.60	$909.25
Title V Revision (per facility)	N/A	$1,518.26

Examples of Permit Application Processing Fees		
Change	Facility A (Non-Title V): Two Engines	Facility B (Title V): Seven Engines
Engine Permit	$1,925.50 - $8,638.80*	$8,444.87 - $37,888.41*
I & M Plan	$725.60	$909.25
Title V Revision	N/A	$1,518.26
Total Per Facility**	$2,651.10 - $9,364.40*	$10,872.38 - $40,315.92*

* Low end estimate represents fee for administrative change and high end estimate represents fee for change of condition

** Estimated fees only includes moving engines from Rule 1110.2 to PR 1179.1, does not include fees for any other equipment subject to PR 1179.1

Natural Gas Boilers

- Boilers that only fire natural gas will be included in PR 1179.1
- Natural gas boilers will be subject to the limits in Rule 1146 and Rule 1146.1, in tables 1146-1 and 1146.1-1, respectively
- Emission limits will apply upon burner replacement or upon 15 years from the date of amendment of PR 1179.1, whichever comes first

PR 1179.1 Applicable Equipment Summary

- Boilers
  - Digester gas, natural gas, and dual fuel
  - Greater than and less than 2 mmbtu/hr
- Turbines firing digester gas and/or natural gas
- Microturbines that fire digester gas or a blend of digester gas and natural gas
  - Microturbines only firing natural gas will be subject to Rule 1147/1147.1
- Engines
  - TBD

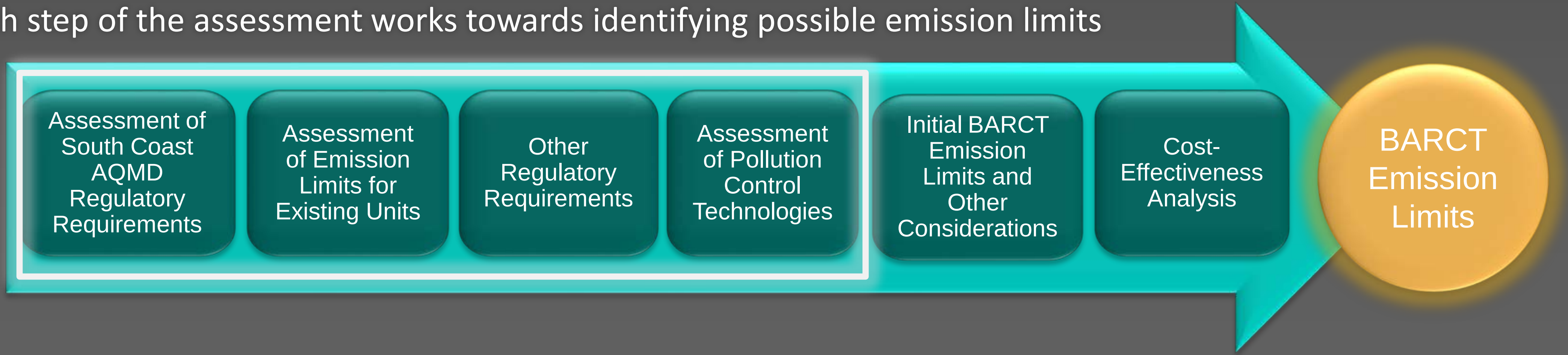
Technology Assessment

Technology Assessment

- A technology assessment will be conducted for the following equipment
  - Boilers - separated by type and size
    - Digester gas and dual fuel
    - Greater than and less than 2 mmbtu/hr
  - Turbines firing digester gas or a blend of digester gas and natural gas
  - Microturbines that fire digester gas or a blend of digester gas and natural gas
    - Microturbines only firing natural gas will be subject to Rule 1147/1147.1
- Natural gas boilers and natural gas turbines have had recent BARCT assessments

BARCT Technology Assessment

- Assesses applicable technologies in order to identify an initial NOx emission limit
  - Once technology assessment identifies an initial NOx emission limit, cost-effectiveness analysis will be conducted to establish the BARCT emission limit
- Technology assessment is specific to the equipment category, fuel type, and may take into account size and application of the equipment
- Four steps in the Technology Assessment
  - Each step of the assessment works towards identifying possible emission limits



Technology Assessment

- Previous working group meeting
  - Identified emission levels of existing units in South Coast AQMD and other air districts using source test data
  - Assessed regulatory requirements in other air districts
- Technology assessment
  - Information provided by control technology suppliers
  - Information gathered from real world applications
- Revisit source tests results for digester gas boilers, dual fuel boilers, and turbines
  - Boilers > 2mmbtu/hr, separated by type (digester gas, dual fuel, co-fired)
  - Turbines using digester gas or blend of digester and natural gas
- Identify the control technology used
- Initial BARCT emission limit recommendations and cost estimation tools

Gas Treatment – Technology Assessment

Digester Gas Treatment System

- Gas treatment technology removes siloxanes, moisture, hydrogen sulfide, and other undesirable contaminants
- Removal of siloxanes from digester gas is important for equipment and control technology to work efficiently and to prevent damage

Three primary types of systems for siloxane removal		
Consumable Media	Regenerative Media	Chiller/Adsorption
Each system can utilize different media or a combination of media		

Characteristics of Media

- Effectiveness of siloxane adsorption depends on media characteristics and contaminants in gas stream
- Common types of media
  - Activated carbon
    - Versatile adsorbent with highly porous and large surface area, suitable to adsorb organic molecules (e.g. siloxanes)
  - Molecular sieve
    - Adsorbent with pores of uniform size, capable of performing selective removal of contaminants at low concentrations (e.g., water molecules, siloxanes, CO_2, and/or H_2S)
  - Silica gel
    - Shapeless and porous adsorbent, with siloxane adsorption capacity about 10 times greater than activated carbon and has high affinity for water

Consumable Media

- Commonly used with activated carbon as media and stored in a series of parallel canisters
  - Activated carbon media adsorbs siloxanes and many other contaminants
  - Canisters are changed out after carbon is saturated and siloxanes begin to break through
  - Activated carbon media is quickly saturated due to adsorption of the many other contaminants, causing frequent change
    - Frequency of media change depends on gas treatment system design
    - Installment and maintenance costs are typically less than regenerative and chiller media systems – less complex system design
    - Removal and disposal of media can have a significant cost[1]
- Removal efficiency depends on gas content and system design

[1] https://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1110_2/aqmd-contract-13432-final-report-2014---revised.pdf?sfvrsn=2

Regenerative Media

- Different types of regenerative media may include molecular sieve, silica gel, clay, and zeolite
  - System consists of at least two media canisters – one processes gas while the other regenerates with hot purged air (300+˚F)
  - Typical online and purge cycle times vary
  - Media change out varies based on gas treatment system design
    - Spent material is non-hazardous and may be landfilled
  - Smaller canisters and less media required compared to consumable media systems

Regenerative Media *(continued)*

- Regenerative media can be enhanced by applying polymeric resins
  - Increases service life
  - Higher adsorbent capacity
  - Contaminants removed more quickly from adsorbent during regeneration
  - Regenerates at a lower temperature
- Higher installation cost than consumable media systems due to complex system design[1]
  - Disposal and removal costs are similar to consumable media
- Removal efficiency depends on gas content and system design

[1]https://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1110_2/aqmd-contract-13432-final-report-2014---revised.pdf?sfvrsn=2

Chiller/Adsorption

- System consists of reducing temperature of the biogas to below dew point to condense out any moisture and siloxanes
- Chiller/adsorption is used in combination with consumable media system
  - Adsorbent media can be used as a polishing filter to remove remaining traces of siloxanes and other contaminants
- Initial installation and maintenance costs are similar to regenerative systems[1]
- Chiller/adsorption system (40˚F) removes 30 to 50% of siloxanes (case study)
- Advanced chiller/adsorption systems (lower temperature) can remove up to 95% siloxanes (case study)

1 https://www.aqmd.gov/docs/default-source/rule-book/support-documents/rule-1110_2/aqmd-contract-13432-final-report-2014---revised.pdf?sfvrsn=2

Applications of Gas Treatment Technologies

- Gas treatment systems at POTWs use a combination of methods
  - Polishing stage can be added to remove siloxanes down to levels that can allow SCR catalyst to operate
- 5 facilities using digester gas treatment technology with SCR on 12 digester gas engines
- 1 facility using digester gas treatment technology with SCR on 3 digester gas turbines
  - Regenerative adsorption with a carbon polishing stage

Boilers – Technology Assessment

NOx Control Technology - Boilers

- Thermal NOx is the largest contributor to NOx emissions from boilers
  - Formed by high flame temperatures
- NOx formation is minimized by reduced flame temperatures, shortened residence time, and increased fuel to air ratio
  - These factors can be reduced by optimizing combustion parameters and/or applying control techniques downstream of combustion zone
- Technologies available for NOx control
  - Low NOx burners (LNB) and ultra-low NOx burners (UNLB)
  - Selective catalytic reduction (SCR)
  - Peak flame temperature reduction
    - Flue gas recirculation (FGR)

Technology Assessment – Boilers
Low and Ultra-low NOx Burners

- Low NOx and ultra-low NOx burners reduce flame temperature and NOx emissions in a combination of ways
  - Controlling air-fuel mixture during combustion
  - Modifying shape or number of flames
- Other peak flame reduction technology is often used with these burners or alone
  - Flue gas recirculation – flue gas returned and mixed with combustion air to lower flame temperature
    - Reduces NOx by 30-55%
  - Considerations
    - Potential flame instability

Technology Assessment – Boilers
Low and Ultra-low NOx Burners *(continued)*

- Digester gas and dual fuel boilers using a low NOx burner can be optimized to achieve <9 ppm with proper tuning and possibly an O_2 trim system
  - Difficulty in achieving constant emissions levels due to variations with the higher heating value (HHV) in the fuel
  - Affects ability for suppliers to guarantee lower limits that are being achieved in practice
  - Suppliers can guarantee 15 ppm for biogas
- Considerations
  - At least one facility experiencing flame out due to siloxane build up
    - Routine cleaning of burner required to maintain burner function – facility opting to treat gas upstream
  - Stakeholders and suppliers have stated that ultra-low NOx burners are unstable with digester gas
    - Can be attributed to varying constituents and quality of digester gas

Technology Assessment – Boilers
Selective Catalytic Reduction

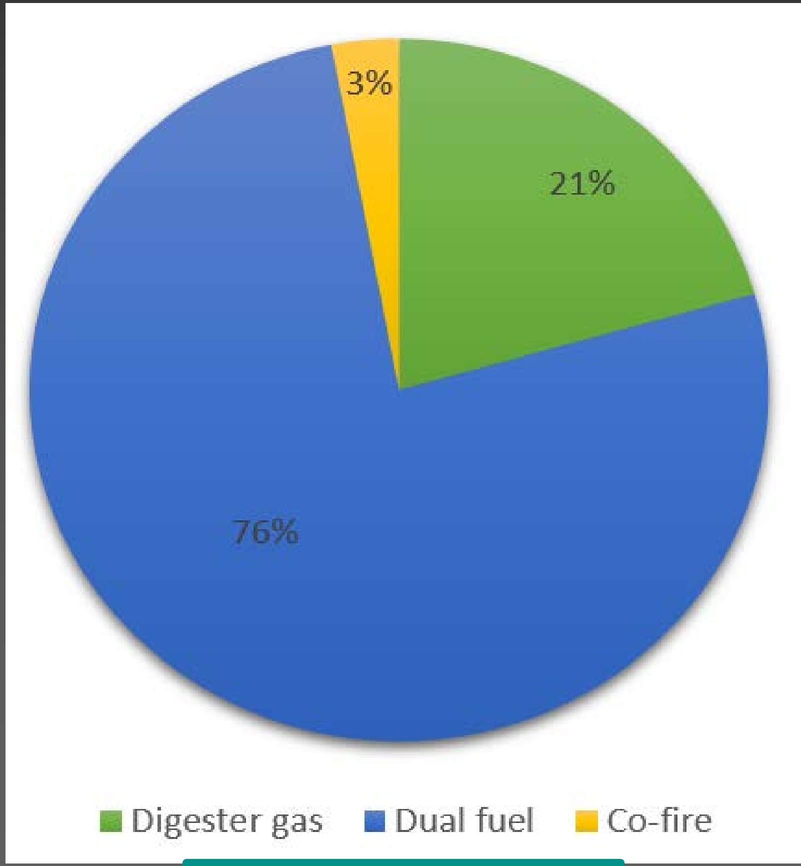
- Primary post-combustion technology for NOx reduction[1]
  - Ammonia is injected into the exhaust gas, which passes through the catalyst reactor, resulting in the reduction of NOx by 90-95%
  - May be used in conjunction with combustion alteration NOx control technologies
- Considerations
  - Requires gas treating technology – catalyst susceptible to fouling if flue gas contains contaminants (e.g., particulates, sulfur compounds, siloxanes, etc.)
  - Requires on-site storage of ammonia or urea
  - Potential for ammonia slip where unreacted ammonia is emitted from control device – ammonia slip catalysts available to control ammonia emissions
  - Limited by range of optimum operating temperature conditions (e.g., 400F to 800F)

[1] https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

Boilers – Source Tests Evaluation

Boiler Assessment

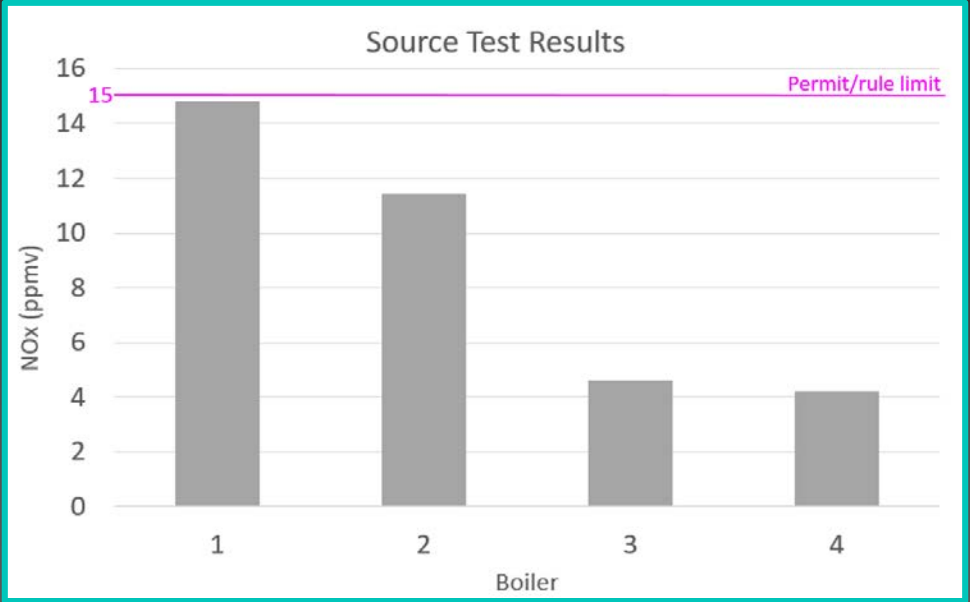
- Boilers > 2 mmbtu/hr assessed categorized as
  - Digester gas (7 boilers)
  - Dual fuel – permitted to fire on either digester gas or natural gas (26 boilers)
  - Co-fired – permitted to fire both digester and natural gas (1 boiler)
    - Source tests results for this boiler will be analyzed with the dual fuel boilers
- More source tests to be assessed
- Assessment for boilers < 2 mmbtu/hr to follow



34 boilers total

Source Test Evaluation – Digester Gas Boilers

- Source tests indicate that low NOx burners are effective in controlling NOx from boilers that are fired on digester gas
- NOx levels of less than 5 ppmv are demonstrated for digester gas boilers that have been retrofit with low NOx burners
  - More information needed to determine if 5 ppmv could be demonstrated consistently
- Boilers 2 and 4 are the same make and model and have varying results between 4.2 – 11.4 ppmv
  - Source tests were conducted a year apart
    - Gas constituents different
    - Boiler tuned differently
    - Age of boilers affecting performance (at least 30 years old)



Boiler	Size	NOx Control Technology	Result	Test Date
1	21 mmbtu/hr	Flue gas recirculation with oxygen trim	14.8 ppmv	2015
2	22 mmbtu/hr	Low NOx burner (retrofit)	11.4 ppmv	2014
3	21 mmbtu/hr	Flue gas recirculation with low NOx burner (retrofit)	4.6 ppmv	2015
4	22 mmbtu/hr	Low NOx burner (retrofit)	4.2 ppmv	2015

Initial NOx Limits for Digester Gas Boilers

	South Coast Rule Limit	Existing Units (source tests)	Other Regulatory Requirements	Technology Assessment	Initial NOx Limit
Dual Fuel (Digester gas) Retrofit/New Install	**15 ppm**	**4.2 – 14.8 ppm**	**9 – 30 ppm**	**9 – 15 ppm**	**9 ppm**

- All burners are 2014 installations and newer
- Cost-effectiveness will be conducted for retrofitting with low NOx burners

Dual Fuel Boilers

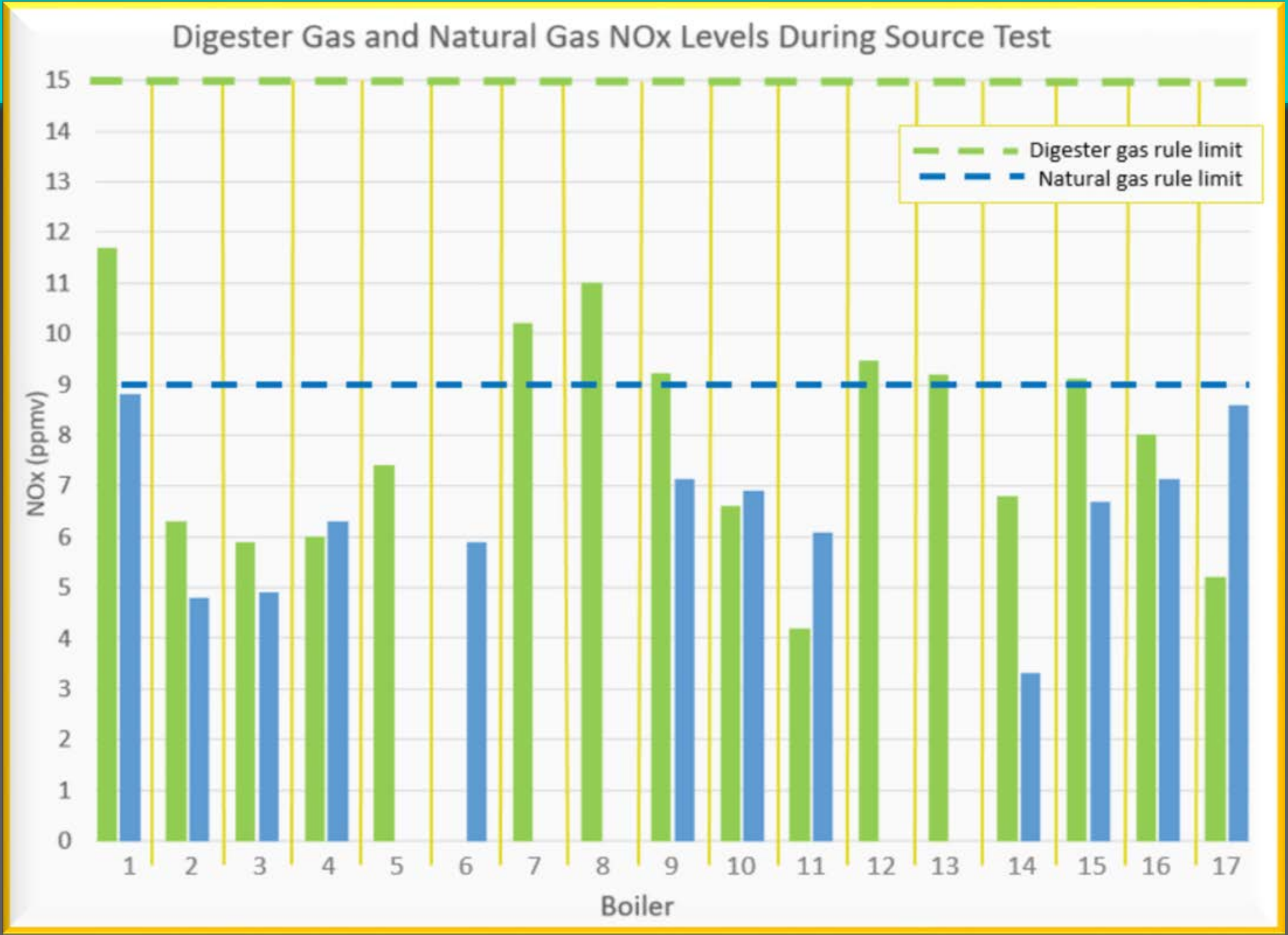
- 26 dual fuel boilers > 2 mmbtu/hr
  - Size range 2.5 mmbtu/hr – 63.5 mmbtu/hr
- Obtained source tests for 17 boilers subject to 15 ppm limit (16 dual fuel and 1 co-fired)
  - Some dual fuel boilers only had source tests for one fuel
- No source tests available for 9 out of the 26 dual fuel boilers with 15 ppm limit
  - Collection of source tests in process
- 1 unit is permitted to fire blended digester gas and natural gas
  - Boiler functioning as dual fuel when source tested
  - Source tests included in dual fuel boiler analysis

Source Test Evaluation – Dual Fuel Boilers

- 16 source tests for dual fuel boilers running on 100% digester gas
  - Range 4.2 - 11 ppm
  - Digester gas has not been treated upstream
- 12 source tests for dual fuel boilers running on 100% natural gas
  - Range 3.3 - 8.8 ppm
- Most boilers using a low NOx burner
- 1 boiler using an ultra-low NOx burner (ULNB)
  - Firing natural gas only for source test
- 2 low NOx burners are retrofits
- 1 atmospheric boiler using low NOx burner with heat recovery
- Boilers size range is 2.5 – 62 mmbtu/hr

Source Test Evaluation – Dual Fuel Boilers *(continued)*

- Digester gas (current limit 15 ppm)
  - Emission level results for all units < 12 ppm
  - Emission level results for 81% of units < 10 ppm
  - Emission level results for 56% of units < 9 ppm
- Natural gas (current limit 9 ppm)
  - Emission level results for all units < 9 ppm
  - Emission level results for 67% of units < 7 ppm
- Dual fuel boilers show emission levels similar to single fuel boilers
- No indication that behavior differs from that of a single fuel boiler
- Staff proposes that dual fuel boilers will be subject to Rule 1146 and 1146.1 when firing 100% natural gas



Initial NOx Limits for Dual Fuel Boilers

	South Coast Rule Limit	Existing Units (source tests)	Other Regulatory Requirements	Technology Assessment	Initial NOx Limit
Dual Fuel (Digester gas) Retrofit/New Install	15 ppm	4.2 – 11 ppm	9 – 30 ppm	9 – 15 ppm	9 ppm

- All burners are 2010 installations and newer
- Cost-effectiveness will be conducted for retrofitting with low NOx burners

Co-fired Boilers

- 1 unit is permitted to allow blended fuel of digester and natural gas
  - Source tested with 100% digester gas and 100% natural gas
- Analyzed as a dual fuel boiler to determine the emission limits for each fuel
- Staff is proposing that the NOx emission limit be based on a weighted average
  - Rule 1146 has provisions in place for calculating the emission limit for co-fired boilers
  - Co-fired boilers located at POTWs would use the compliance limits from PR 1179.1 to calculate the weighted average limits

Turbines – Technology Assessment

NOx Control Technology – Turbines

Assessment of Pollution Control Technologies

NOx control technologies available for gas turbines

Steam/water injection

- Controls to 25 ppmv
- Currently used at one facility

Selective Catalytic Reduction (SCR)

- Requires gas clean up
- Up to 95% NOx reduction
- Used on several biogas units

Lean premix combustion

- Not available for retrofit – replacement only
- Controls to 9 ppmv
- No known POTW applications

Technology Assessment – Turbines Water/Steam Injection

- Injection of water or steam into high temperature flame zone, lowering combustion zone temperature and reducing NOx formation
  - Water injection reduces NOx by 80 – 95%
  - Steam Injection reduces NOx by 70 – 85%
- Addition of water or steam increases mass flow through the turbine and creates a small amount of additional power
- Considerations
  - Water needs to be demineralized, which adds cost and complexity
  - Imprecise application leads to some hot zones with higher NOx levels
  - Increases fuel use and CO emissions
  - Shorten equipment life
- Need to obtain more information on the ability to retrofit turbines with a water injection system
- One facility currently using this technology to achieve 65% NOx reductions

Technology Assessment – Turbines
Selective Catalytic Reduction

- Primary post-combustion technology for NOx reduction[1]
  - Ammonia is injected into the exhaust gas, which passes through the catalyst reactor, resulting in the reduction of NOx by 90-95%
  - May be used in conjunction with combustion modification NOx control technologies
- Considerations
  - Requires gas treating technology – catalyst susceptible to fouling if flue gas contains contaminants (e.g., particulates, sulfur compounds, siloxanes, etc.)
  - Requires on-site storage of ammonia or urea
  - Potential for ammonia slip where unreacted ammonia is emitted from control device – ammonia slip catalysts available to control ammonia emissions
  - Limited by range of optimum operating temperature conditions (e.g., 400F to 800F)

[1] https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

Applications for Selective Catalytic Reduction on Turbines

- SCR has been used on several biogas engines and turbines
  - 12 digester gas engines using SCR with a gas cleaning system
  - 3 turbines in South Coast air district demonstrating 90% reduction with SCR
- 2 turbines in the San Joaquin Valley used SCR to control NOx emissions to <5 ppm
- SCR is shown to operate with a properly designed and maintained gas clean treatment system

San Joaquin Valley turbines

- Installed SCR design
  - Inlet NOx: > 25 ppmv
Outlet NOx: < 5 ppmv
NH_3 slip: < 10 ppmv
  - Catalyst life: 5 years
- Source tests for 2 turbines:
  - 2.5-3.9 ppmv
  - 7 tests over 5 years of operation
- SCR achieving 80-90% reduction
- $1.12 million (2 SCRs – equipment only)

Technology Assessment – Turbines
Lean Pre-mixed Combustion

- Prior to combustion, gaseous fuel and compressed air are pre-mixed, minimizing localized hot spots that produce elevated combustion temperatures and therefore, less NOx is formed
- Considerations
  - Requires that the combustor becomes an intrinsic part of the turbine design
  - Not available as a retrofit technology; must be designed for each turbine application

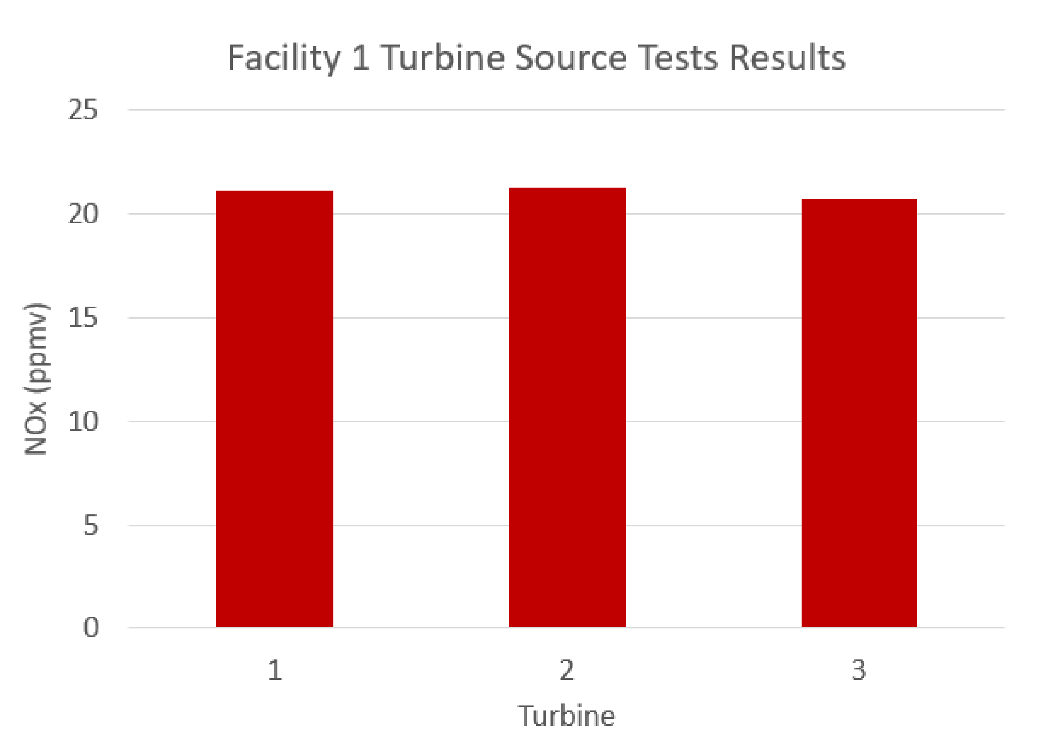
Turbines – Source Tests Evaluations

Turbine Assessment

- Analyzed 8 digester gas turbines
  - Emission levels demonstrated
  - Control technology
  - Turbine equipment
- 6 turbines in South Coast AQMD
  - Facility 1 – 3 digester gas turbines
  - Facility 2 – 3 digester gas turbines
- 2 turbines at one POTW permitted by SJVAPCD

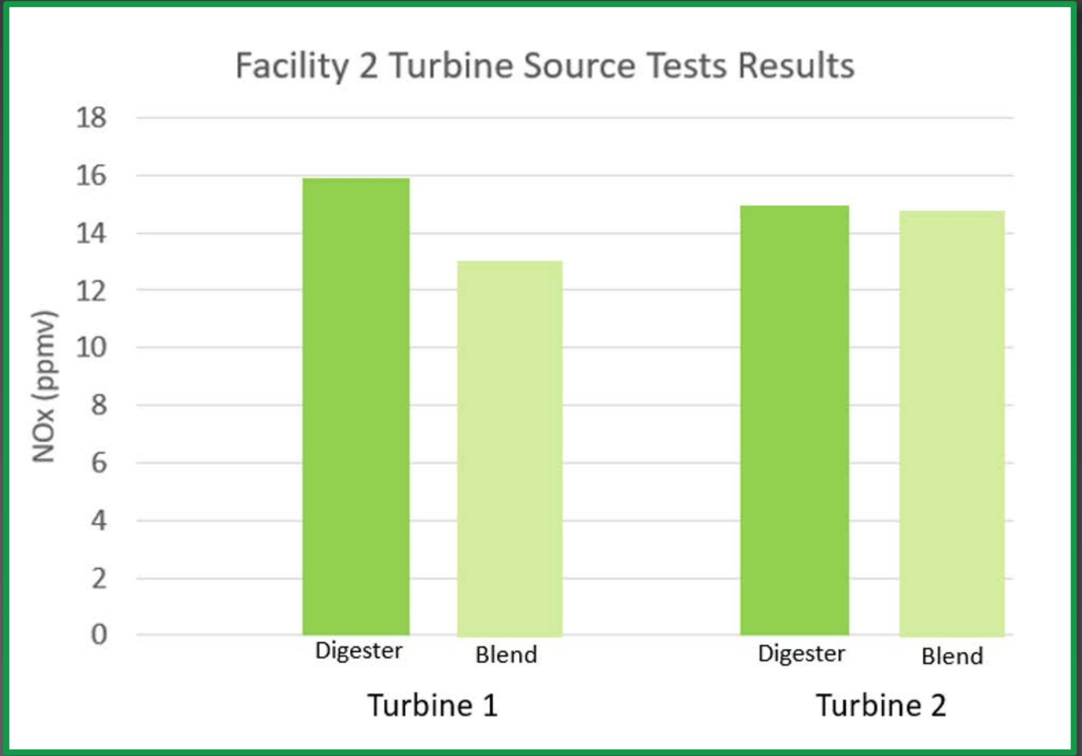
Facility 1 – South Coast AQMD

- 3 digester gas turbines
- Use water injection for NOx control
  - No SCR installed
- Demonstrate 65% NOx reduction with water injection
  - Uncontrolled NOx (70 ppm) reduced down to source tests results (22 ppm)



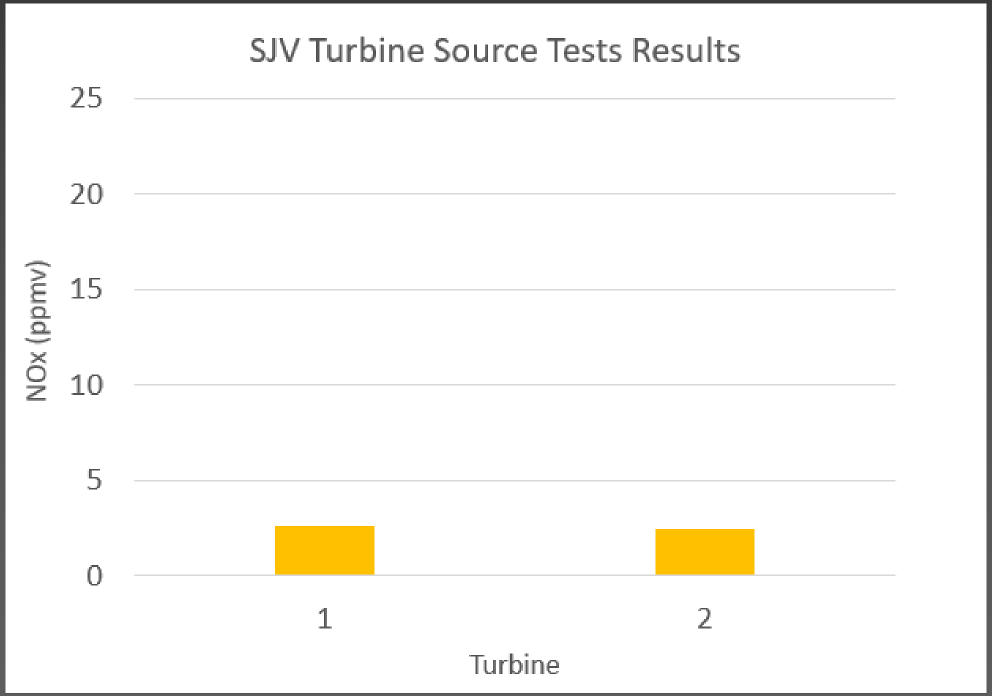
Facility 2 – South Coast AQMD

- 3 turbines
  - Capable of firing a blend of natural gas and digester gas
  - Firing 60% digester gas when blending
  - Maximum uncontrolled emissions are 213 ppmv (inlet NOx)
    - Source tests for blended fuel are 13 ppm and 14.3 ppm
    - SCR demonstrating up to 94% reduction from inlet NOx
- Using SCR for NOx control
  - No water injection system installed
  - Gas treatment required for SCR performance



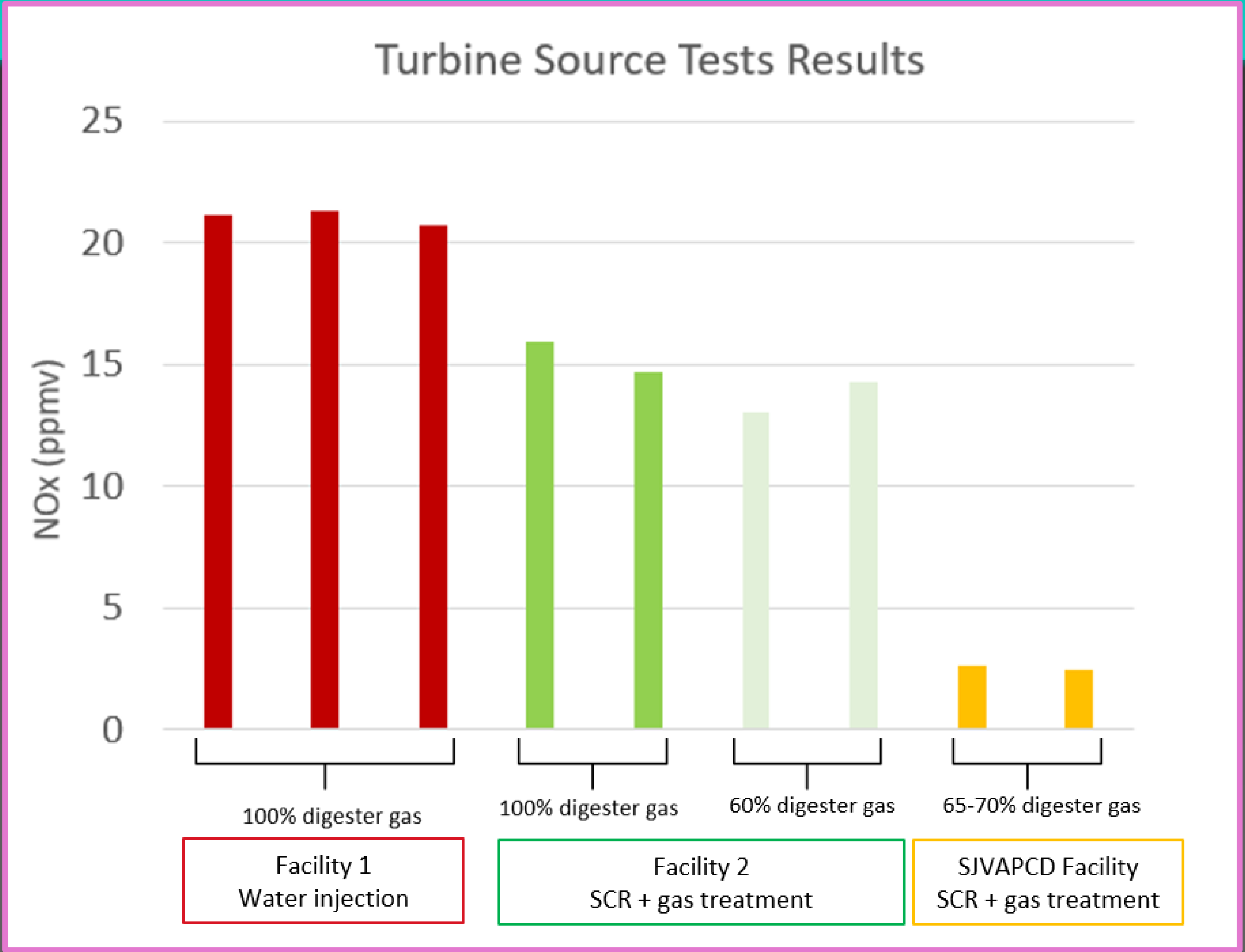
SJVAPCD Facility

- 2 turbines that fired a blend of digester and natural gas (65-70% digester gas)
  - Used turbines (Rolls Royce) purchased in 2004
  - Demonstrated 24-25 ppmv NOx with water injection only
  - In 2007, SJVAPCD lowered the limits from 25 ppmv to 5 ppmv
  - In 2011, discontinued water injection and implemented SCR and gas clean up to achieve 5 ppmv NOx
  - Ceased operation in 2016 when both turbines became permanently inoperable due to the age of the equipment



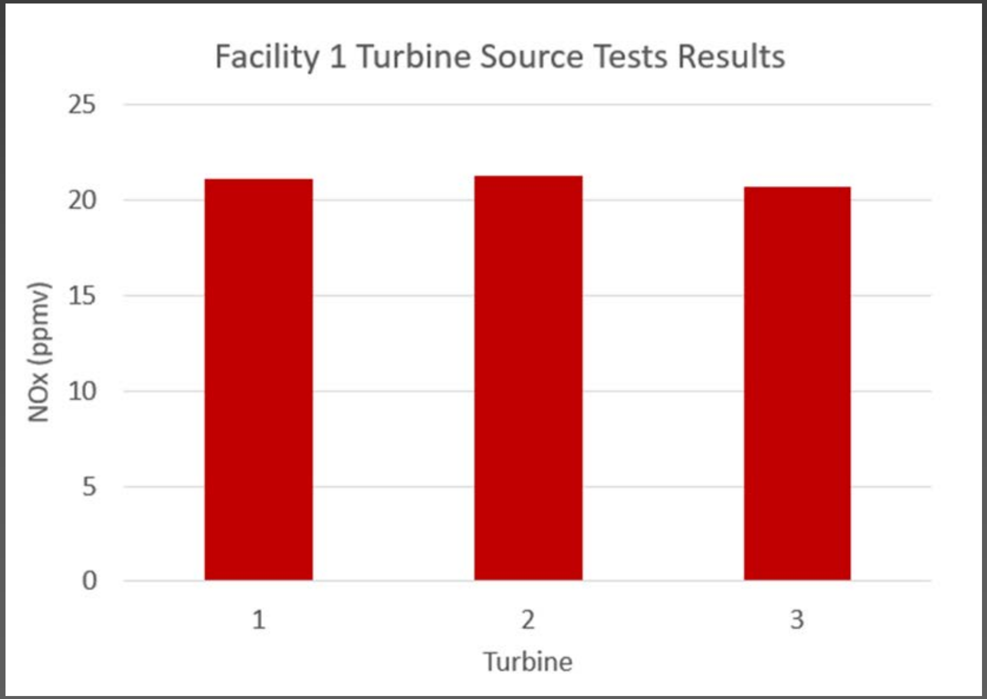
Source Test Evaluation Summary

- Turbines using SCR and gas treatment show significantly lower NOx emission levels than turbines using water injection alone
- SCR and gas treatment implementation resulting in up to 94% reduction in NOx emissions from digester gas turbines



Source Test Evaluation Summary

- Turbines using water injection only could reach lower NOx levels with the addition of SCR
- Source tests results are < 22 ppm for these turbines with water injection
- 90% reduction in NOx emissions with the addition of SCR and gas treatment would result in NOx emissions < 2.5 ppm



Initial NOx Limits for Digester Gas Turbines

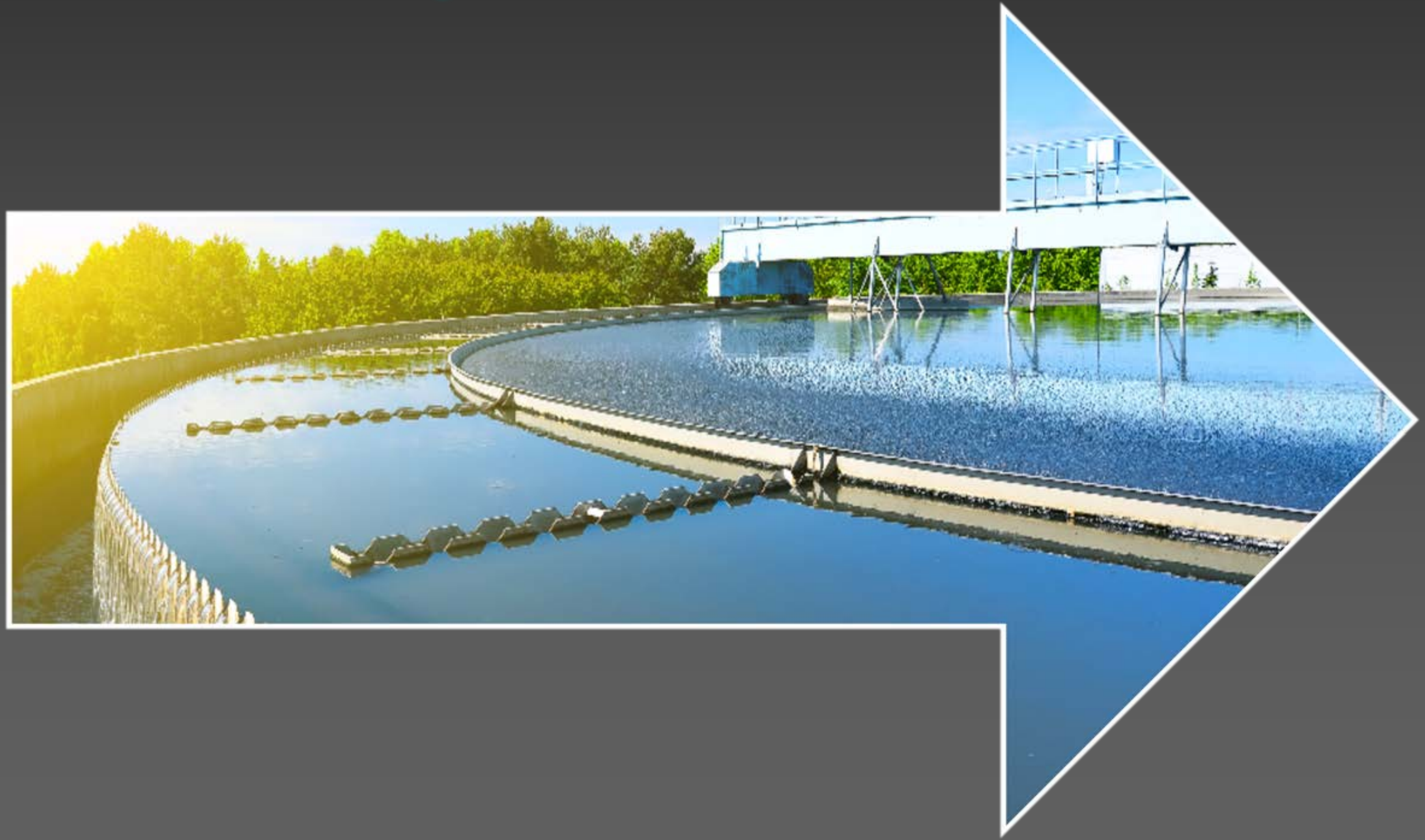
	South Coast Rule Limit	Existing Units (source tests)	Other Regulatory Requirements	Technology Assessment	Initial NOx Limit
Retrofit with SCR	**Only permit limits apply**	**2.5 - 22 ppm**	**3 - 15 ppm**	**< 2.5 ppm**	**2.5 ppm**

Cost Estimations

Cost Estimations

- Cost estimates will be obtained from:
  - U.S. EPA's Air Pollution Control estimation spreadsheet for SCR costs
    https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost manual
  - South Coast AQMD's biogas toolkit cost estimator for gas treatment system costs
    http://www.aqmd.gov/home/rules-compliance/rules/support-documents#r1110-2
  - Vendor quotes
  - Facility information
- Staff is seeking cost information from facilities

Next Steps



- BARCT assessment on microturbines and small boilers
- Cost analysis
- Draft rule language

Rulemaking Schedule

4-6 weeks	1st Quarter 2020	1st/2nd Quarter 2020	2nd Quarter 2020
Next Working Group Meeting	Public Workshop	Set Hearing	Public Hearing

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