TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 8, 2014

EPA Docket Center
U.S. Environmental Protection Agency
Mail Code 2822T
1200 Pennsylvania Ave, NW
Washington, DC 20460

Attn: Docket ID No. EPA–HQ–OAR–2013–0495

Re: Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule

Dear Sir or Madam:

The Texas Commission on Environmental Quality (TCEQ), the Public Utility Commission of Texas (PUC), and the Railroad Commission of Texas (RRC) appreciate the opportunity to provide joint comments on the U.S. Environmental Protection Agency's (EPA's) proposal published in the January 8, 2014, edition of the *Federal Register* entitled: "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units."

Enclosed, please find our detailed comments relating to the EPA proposal referenced above. If you have any questions concerning the enclosed comments, please contact Mr. Michael Wilson, P.E., Director, Air Permits Division, TCEQ Office of Air, (512) 239-1922, or at mike.wilson@tceq.texas.gov.

Sincerely,

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Executive Director
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Brian H. Lloyd
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Enclosure

Comments from the Texas Commission on Environmental Quality, Public Utility Commission of Texas, and Railroad Commission of Texas on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule

Docket ID No. EPA-HQ-OAR-2013-0495

The Texas Commission on Environmental Quality (TCEQ), the Public Utility Commission of Texas (PUC), and the Railroad Commission of Texas (RRC) jointly provide the following comments on the U.S. Environmental Protection Agency's (EPA's) proposed rule referenced above. The proposed rule was published in the January 8, 2014 issue of the *Federal Register* (79 FR 1430). All comments in this document are submitted as joint comments between the TCEQ, PUC, and RRC unless otherwise noted.

I. Background

On April 13, 2012, EPA proposed new source performance standards (NSPS) for emissions of carbon dioxide (CO_2) for new, affected fossil fuel-fired electric utility generating units (EGUs). EPA received more than 2.5 million comments on the proposed rule, including comments from the TCEQ and PUC opposing numerous aspects of the proposed 2012 rule. In the preamble to the January 8, 2014 proposed rule, EPA explains that after consideration of information provided in those comments, as well as consideration of continuing changes in the electricity sector, EPA has determined that revisions to its proposed approach are warranted. Accordingly, EPA has withdrawn the April 13, 2012 proposal and published new proposed standards for these sources.

EPA's proposed 2014 rule requirements, which are limited to new sources, propose a standard for utility boilers and integrated gasification combined cycle (IGCC) units based on partial implementation of carbon capture and storage (CCS) as the best system of emission reduction (BSER). The proposed emission limit for those sources is 1,100 lb CO_2/MWh. EPA has also proposed standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lb CO_2/MWh for units exceeding 850 MM BTU/hr, and 1,100 lb CO_2/MWh for units between 250 - 850 MM BTU/hr.

TCEQ, PUC, and RRC believe that the State of Texas would be significantly impacted by the proposed standards, if adopted. Although EPA's 2014 proposal has addressed some of the problems and issues with the 2012 proposal, there are numerous, major legal, practical, and technical issues which remain. For the reasons provided in more detail below, TCEQ, PUC, and RRC oppose adoption of the proposed 2014 rule, and strongly recommend that EPA withdraw the rule until these numerous issues are addressed and resolved.

II. Comments on the Proposed Rules

A. Legal basis for the proposed rulemaking.

1. **The Energy Policy Act of 2005 (EPAct05) clearly prohibits the use of CCS technology funded by the federal government as support for a finding under the Federal Clean Air Act (FCAA or CAA) section 111 that the technology is adequately demonstrated as a BSER.**

A standard of performance promulgated under FCAA section 111 is required to be based on an emission control method or system which the Administrator determines has been "adequately demonstrated." Although the FCAA does not explicitly define "adequately demonstrated," there are a number of technical and legal reasons why CCS cannot reasonably be considered an adequately demonstrated technology. As discussed below, portions of EPAct05 and the Internal Revenue Code (IRC) preclude EPA from making a determination that CCS is an adequately demonstrated technology.

TCEQ, PUC, and RRC do not agree with EPA's interpretation of section 402(i) of EPAct05 or IRC section 48A. In the Technical Support Document (TSD, "Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs"), EPA gives far too much weight to the word "solely" in the clauses in question in EPAct05 and the IRC. This word must be read together with the other part of this sentence in order to provide the proper context. The phrase "solely by reason of the use of the technology" only modifies "level of emission reduction," especially in the IRC where those two phrases are in brackets. In other words, the correct reading is: No technology or level of emission reduction that can only be achieved through the use of that technology by one or more facilities receiving federal assistance can be considered adequately demonstrated for purposes of section 111. Therefore, CCS, once funded or receiving a tax credit at any project, cannot be deemed BSER for coal-fired units.

A closer look at EPAct05 further shows that EPA's proposed determination of CCS as an adequately demonstrated technology for purposes of FCAA section 111 is not consistent with the intent or provisions of EPAct05. The Clean Coal Power Initiative was established in 2002 as a partnership between government and industry focusing on implementing the President's National Energy Policy recommendation to increase investment in clean coal technology. This initiative was codified in the EPAct05 and authorized Department of Energy (DOE) funding assistance for projects seeking to advance efficiency, environmental performance, and cost competitiveness, such as CCS. Eligible clean coal projects are those using technology that is well beyond what has been demonstrated as commercially available. The objective of this portion of EPAct05 - to promote, through federal funding and tax credits, the development of projects that achieve efficiency and environmental performance beyond currently demonstrated technologies – is supported by sections 402(a) and 402(i) of EPAct05 and IRC section 48A. These provisions of EPAct05 and the IRC protect these advanced projects from premature regulation. Clearly then, Congress sought to advance emission reduction technologies like CCS in the coal-fired utility industry through a non-regulatory mechanism. If EPA deems the emission reduction technology CCS to be "adequately demonstrated" for purposes of BSER under section 111 of the CAA, then federal assistance given to these CCS projects is not consistent with sections 402(a) or 402(i) of EPAct05.

TCEQ, PUC, and RRC also do not agree that EPA should receive deference in its interpretation of EPAct05, as the EPA asserts in footnote 8 of the TSD. The EPA is not interpreting the CAA from which EPA derives its authority to propose and promulgate these standards; EPA is interpreting provisions of other acts that reference a particular section of the CAA. In addition, no interpretation of the language is necessary, because the language is clear that both EPAct05 and IRC section 48A were specifically enacted to explicitly exempt certain projects from consideration by EPA as meeting the requirements for "adequate demonstration" under FCAA section 111.

Lastly, TCEQ, PUC, and RRC do not agree that the EPA can treat a facility as not having received any assistance under EPAct05 merely because EPA does not receive any information confirming that a particular facility received assistance. It is EPA's burden, not industry's, to show that the

EPAct05 and IRC provisions do not prohibit consideration of CCS in determining BSER under section 111. EPA has the obligation of investigating the sources it selects for setting BSER. If the EPA lacks sufficient information to determine whether a particular facility received assistance under EPAct05 in order to comply with section 402(i), then the EPA should not be relying on that facility for setting BSER.

2. EPA has not sufficiently justified or demonstrated the need for, or benefits of, the proposed greenhouse gas (GHG) NSPS rule for EGUs. EPA should reconsider the efficacy of the proposed GHG NSPS rule for EGUs and withdraw it.

In the preamble to the proposal (79 FR 1496), EPA describes the purpose for the rulemaking and states that, "...the proposed rule [to limit GHG emissions from the largest stationary category] will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks." However, EPA then posits that there will be no cost or benefit associated with the rule based on their Integrated Planning Model (IPM) modeling, and that the rule will not result in any emissions reductions from the largest source of GHGs in the country. If the rule will not result in any measurable emissions reductions, then the purpose of the rulemaking is absent. TCEQ, PUC, and RRC strongly recommend that EPA reconsider the efficacy of the proposed GHG NSPS proposed rule and withdraw it.

Even though EPA's own modeling and analysis shows that the proposed rule has no benefits and EPA acknowledges that lack of benefits, EPA argues that "by clarifying that in the future, new coal-fired power plants will be required to meet a certain performance standard, this rulemaking reduces uncertainty and may well enhance the prospects for new coal-fired generation and the deployment of CCS..." (79 FR 1496). The logic EPA relies upon to claim that no new coal-fired EGUs will be built in the foreseeable future contradicts their reasoning that establishing a standard for coal-fired EGUs based upon CCS may "...enhance the prospects for new coal-fired generation and the deployment of CCS...." EPA's projection that no new coal fired EGUs will be built is based upon the logic that the lower cost electric generation alternative will be selected. Currently, NGCC units are the relative lower cost alternative to coal-fired EGUs. Information in the proposed rule identifies that requiring CCS on future coal-fired EGUs will make coal-fired EGUs relatively even more expensive than an NGCC unit. EPA offers no explanation for how adopting a rule that makes building future coal-fired EGUs with CCS relatively more expensive than NGCC (the lower cost alternative) may enhance the prospects for new coal-fired generation and the deployment of CCS.

Promoting and advancing control technology that cannot be defended on the merits of technological and economic feasibility is not the purpose of FCAA section 111. The excerpt from the Senate Committee Report to the 1970 CAA amendments that EPA included in the preamble of the proposal (79 FR 1464) clearly states the purpose of section 111: "The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach." By the EPA's own admission in the preamble of this proposal (79 FR 1433), the rule will have negligible benefits. EPA has not demonstrated that the proposed rule satisfies the Senate committee's stated purpose of FCAA section 111.

In addition, there is no basis in section 111 for EPA to promulgate a standard for new sources for the primary purpose of ultimately regulating existing sources. EPA has acknowledged that the proposed standard will not result in meaningful reductions in CO_2 emissions because in EPA's projections, no new coal-fired EGUs will be built in the near future. EPA further states (79 FR 1496), "The proposed rule will also serve as a necessary predicate for the regulation of existing sources with this source category under CAA section 111(d)." If the 'overriding purpose' for section 111 is to prevent *new* pollution, EPA has proposed an admittedly insufficient standard regulating sources that may never be built, in order to justify regulating existing sources of pollution.

3. The proposed rule will result in disparate impacts on States because it does not adequately consider regional differences in power infrastructure, geologic conditions, and other factors.

The proposed rule runs afoul of prior court interpretations (Sierra Club v. Costle, 657 F.2d 298) related to BSER, because the proposed standard gives a competitive advantage to one state over another. The proposed rule creates disparity between states based upon at least four factors that were not adequately considered by EPA. The proposed rule creates advantages for states that have suitable geologic formations and oil reservoirs for CCS; that currently utilize liquid fuels; that have adequate natural gas infrastructure to support additional NGCC turbines; and that are served with power distribution grids that do not require frequent startups, shutdowns, and reduced load (SSRL) operations. EPA attempts to justify proposing a rule that creates clear winners and losers between states by referencing International Harvester Co. v. EPA, 478 F. 2d at 930 as a basis to promulgate standards that not every new source in the category would be able to achieve. Standards proposed by EPA under section 111 of the CAA are national standards that should apply equally to all states without creating adversity or advantage to any given state.

The proposed rule contains a standard that EPA acknowledges cannot be met on a national basis, because the standard is based upon CCS and suitable geological formations do not exist for CCS across the nation. States with suitable geologic formations and states where captured CO_2 can be used for EOR have a competitive advantage over other states in attracting a particular type of electrical generation (coal-fired units) or in complying with the proposed standard. EPA excludes liquid fired units from meeting the standard based upon CCS, because liquid fired units are usually located in areas where pipeline natural gas is not available, like Hawaii; however, EPA is dismissive about location limitations for potential coal-fired power plants where EOR could offset the cost of CCS. The proposed rule predicts that NGCC units will be the most predominantly built EGUs in the foreseeable future, partly because of the lower price of natural gas and partly because the NGCC BSER is easily achievable, yet the proposed rule does not evaluate the natural gas pipeline infrastructure availability in the North and Northeast U.S. to support new NGCC. The EIA 2014 Annual Energy Outlook Early Release Report (released December 2013) indicates 49.6 GW of coal-fired power plant capacity (a significant portion in the North and Northeast) are expected to retire by 2018. States located in the North and Northeast experienced propane and gas shortages during the winter of 2013-2014, even without the additional demand of new NGCC units. States without adequate natural gas pipeline infrastructure will be at a disadvantage, because their power prices would likely be higher, since power will have to be transported into these states. EPA's proposed BSER standard for NGCC may not be achievable for turbines that frequently operate in SSRL operations. States that are served with power distribution grids that do not require frequent SSRL operations have an advantage in complying with the proposed standard merely based upon where they are located and how they are called upon to operate. EPA did not evaluate variable market conditions and the attainability of the NGCC units to achieve the standards with frequent SSRL operations.

B. Environmental Impact of the Proposed Rule.

1. **The EPA's claimed health co-benefits of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) reductions from the proposed rule are incorrect and invalid because the rule would actually result in an increase in NO_X emissions. Additionally, the EPA has not evaluated the impact of the additional water consumption that CCS requires.**

EPA claims in its Regulatory Impact Analysis (RIA) that reducing power sector CO_2 emissions with this proposed rule would also reduce emissions of SO_2 and NO_X, which would in-turn yield health benefits from reductions in fine particulate matter and ground-level ozone (*Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, Section 5.7.2, page 5-39). However, Table 5-10 of the same RIA clearly indicates that partial CCS on a coal-fired electric generating unit would actually result in an increase in NO_X emissions from a coal-fired EGU on a pound per megawatt-hr basis (lb/MWh) and a tons per year basis (*Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, Section 5.6, page 5-35). This increase in NO_X emissions results from the impact of the parasitic load demand and additional steam requirements of the CO_2 capture technology on the net plant efficiency. This increase in NO_X emissions from CCS is also documented in the U.S. DOE National Energy Technology Laboratory (NETL) reports cited by EPA (*Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, May 27, 2011, DOE/NETL-2011/1498, Section 3.2.5). According to the NETL report, 50 percent CO_2 capture on a supercritical pulverized coal (PC) unit would decrease the net plant efficiency from 39.3 percent to 32.9 percent, forcing the unit to operate at a higher firing rate to maintain the same net generation. The NETL report estimates this impact to the net plant efficiency would increase the NO_X emissions from 0.608 lb/MWh to 0.646 lb/MWh. The EPA has failed to evaluate the environmental impact of the NO_X emission increase that would result from the proposed rule.

Furthermore, while the EPA discusses extensively the possible impacts of climate change on water resources in the RIA for this proposed rule, the EPA only mentions in passing the increased water demand that CCS would require for both a pulverized coal-fired unit and an IGCC unit. The EPA states that the partial CO_2 capture approach would "trim the cooling water requirement of the direct contact cooling system," (*Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, page 5-19). However, the NETL report that the EPA cites indicates that even at the partial CO_2 capture rates necessary to meet the proposed standard, the raw water consumption rate for a supercritical PC unit increases by 26 percent and for an IGCC unit, the raw water consumption rate would increase by at least 7 percent (*Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, May 27, 2011, DOE/NETL-2011-1498, pages 481-482). The EPA has not evaluated the impact of the additional water demand of the technology that is required to comply with the proposed rule.

C. Feasibility of the proposed rule.

1. **The EPA has not adequately demonstrated the feasibility of the proposed CO_2 standard for new coal-fired EGUs. A standard of performance must be**

evaluated on the merits of the standard's technological and economic feasibility, not mere speculation of the feasibility in the future.

Section 111 of the FCAA requires EPA to consider costs and achievability when establishing a standard of performance, including a determination that the required emission control method or system has been "adequately demonstrated." Although the FCAA does not explicitly define "adequately demonstrated," there are a number of reasons why CCS cannot reasonably be considered an adequately demonstrated technology at this time.

No operating EGU has demonstrated the actual effectiveness and achievability of CCS in terms of the proposed standard. EPA claims that new coal-fired EGUs should be able to meet the proposed standard with partial CCS. However, there has not been a single full-scale commercial demonstration of CCS to support EPA's assertion. All four of the United States projects cited by the EPA (Kemper County Energy Facility; Summit Power's Texas Clean Energy Project; Hydrogen Energy California Project; and W. A. Parish Post-Combustion CO_2 Capture and Sequestration Project) received funding from the U. S. DOE and are projects that are part of the NETL's ongoing research on CO_2 capture. Projects that are receiving substantial government funding do not serve as a demonstration of economic feasibility.

The EPA attempts to backfill the lack of any current full-scale commercial demonstration of technological feasibility for CCS on coal-fired EGUs by citing literature documentation and the implementation of components of CCS in industry outside the electric utility sector. However, the EPA ignores the technical and economic challenges for installing CO_2 capture technology on coal-fired EGUs raised by some of the same groups that the EPA cites in their documentation, such as the U.S. DOE NETL reports. Furthermore, while it is true that components of CCS technology have been in use in other industrial sectors, that does not necessarily demonstrate the technological and economic feasibility of the combined technology on a coal-fired facility in the electric utility sector.

EPA's own guidance for PSD permitting of GHG (*PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011) acknowledges that "While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases." The same guidance document notes that "...on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."

2. **The TCEQ, PUC, and RRC disagree with EPA's position that CCS should not undergo a Science Advisory Board (SAB) review.**

EPA has taken the position that CCS should not undergo an SAB review because the "portion of the rulemaking addressing coal-fired power plants focuses on carbon capture and the regulatory mechanisms for addressing potential risks associated with carbon sequestration are not within the scope of the Clean Air Act." Clearly, carbon sequestration is a necessary component of carbon capture and storage, and successful carbon sequestration is essential to the rule's intent to reduce carbon dioxide emissions. The SAB states in their January 29, 2014 letter, "Carbon sequestration, however, is a complex process, particularly at the scale required under this rulemaking, which may have unintended multi-media consequences. The Board's strong view is that a regulatory framework for commercial-scale carbon sequestration that ensures the protection of human health and the environment is linked in important systematic ways to this rulemaking. Research and information from the EPA, Department of Energy, and other sources related to carbon sequestration merit scientific review by the National Research Council or the

EPA." The SAB's comments clearly bring into question EPA's determination that CCS is an adequately demonstrated technology. All EPA's regulations must be based on transparency and the best science available. Unfortunately, this does not appear to be the case with respect to EPA's position on SAB review of CCS.

The TCEQ, PUC, and RRC are also concerned that EPA has not complied with U.S. Office of Management and Budget (OMB) peer review guidance for highly influential scientific assessments as discussed in the February 3, 2014, letter from the Center for Regulatory Effectiveness to The Honorable Gina McCarthy. EPA's assessment of CCS technology must be subjected to independent, external peer review before the rulemaking goes forward and especially before a final rule is sent to OMB for review.

3. **It is not appropriate for EPA to rely upon current low natural gas prices and assumptions about future natural gas prices to justify the proposed GHG NSPS rule. Natural gas prices have historically been highly volatile, especially over the previous decade.**

As is illustrated by Figure 1 on the following page, the price of natural gas has been highly volatile. It is inappropriate and irrational for EPA to assume that natural gas will remain at a low price indefinitely. While EPA claims that coal-fired EGUs will not be economically competitive even at higher natural gas prices, these claims are founded on faulty assumptions. EPA is assuming that the future natural gas prices can be reliably predicted, but history has proven otherwise. In the 2000 Annual Energy Outlook report, the Energy Information Administration (EIA) failed to predict the significant spikes and swings in the price of natural gas that occurred between 2000 and 2009. The price of natural gas has been on an upward trend since April 2012.

EPA's own regulations on natural gas production, such as the oil and natural gas NSPS and revisions to the National Emission Standards for Hazardous Air Pollutants (NESHAP) rules for oil and natural gas sectors, which were finalized at approximately the same time, April 2012, will increase costs for natural gas producers and thereby increase the cost of natural gas. Similarly, this proposed NSPS rule on CO_2 emissions from electric utilities may affect the cost of natural gas by forcing a reduction in demand in other fuels such as coal. The possibility of increased exports of liquefied natural gas may also exert pressure on domestic natural gas supplies, and thus affect the cost and availability of natural gas for power generation.

Finally, the price of natural gas is only one factor that power companies consider when evaluating options for new generation. TCEQ, PUC, and RRC note that coal-fired power plants have been constructed in the past when the cost of natural gas was much less than EPA's claimed critical threshold of $10.94/MMBtu (*Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, Section 5.9.1, page 5-48).

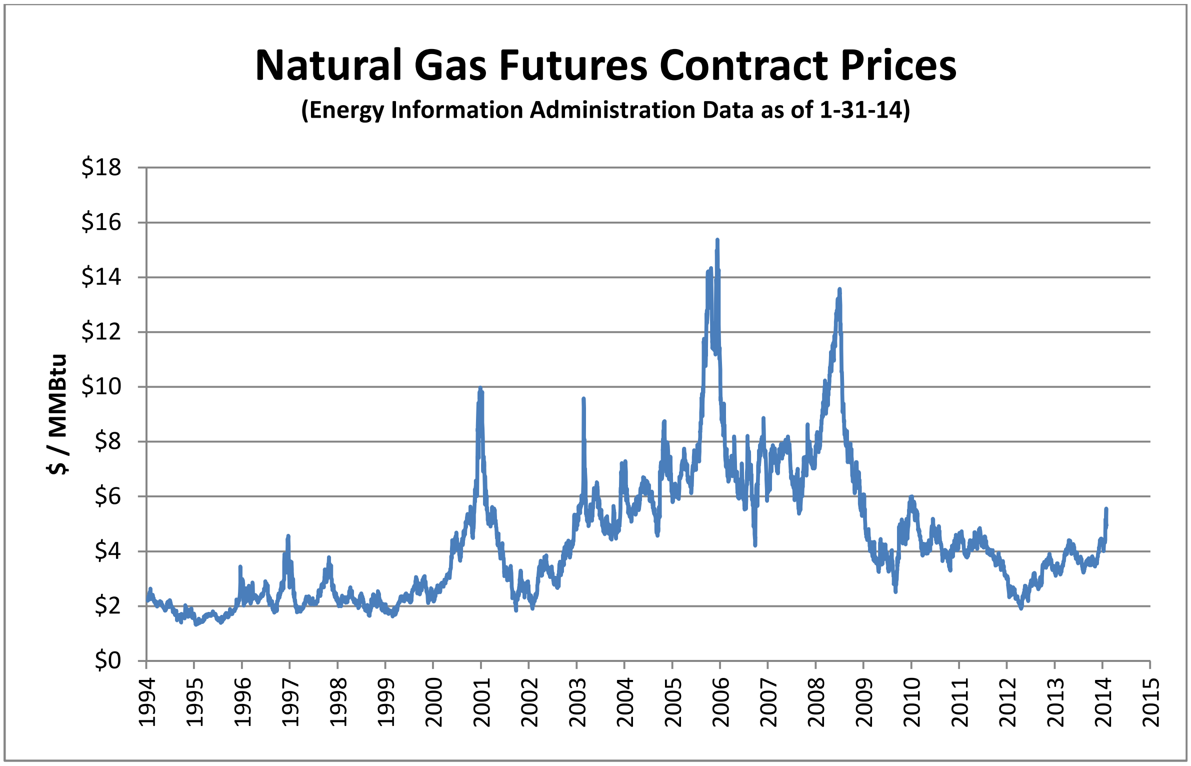

Figure 1: Historic Natural Gas Futures Contract Prices, Source: EIA Online Data.

4. The EPA misrepresents the importance of the levelized cost of electricity (LCOE) data that the EPA uses to justify its claim of economic feasibility. LCOE is not the sole determining factor for companies when deciding what type of power plants to build.

The EPA suggests that because the LCOE of a new coal-fired power plant with partial CCS is comparable to that of a new nuclear power plant, that the cost of new coal-fired generation that includes CCS is reasonable today (79 FR 1477). However, LCOE is only one factor that companies consider when deciding what type of plant to build. The EIA, from which the EPA based its LCOE data, indicates that numerous other factors affect power plant investment decisions.

> *It is important to note that, while levelized costs are a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations.* (Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013, U.S. Energy Information Administration, p. 1)
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> *Policy-related factors, such as investment or production tax credits for specific generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future polices, may cause plant owners or investors who finance plants to place a*

> *value on portfolio diversification. While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not well represented in the context of levelized cost figures.* (Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013, U.S. Energy Information Administration, p. 2)

5. **A May 2013 report by the NETL disputes the EPA's claims regarding the technological and economic feasibility of CCS on coal-fired power plants. The NETL indicates that additional research is needed to further develop CO_2 capture technologies. The EPA should withdraw the rule until additional research is conducted and the issues raised by the NETL are addressed.**

In their 2013 report, the NETL provided an update to the research and development of advanced CO_2 capture technologies for coal-based power systems being conducted by the NETL. The NETL disputes the EPA's claim that CCS is adequately demonstrated and clearly indicates in the report that CO_2 capture technologies are not ready for implementation on coal-fired power plants.

> *There are commercially-available CO_2 capture technologies that are being used in various industrial applications. However, in their current state of development these technologies are not ready for implementation on coal-based power plants for three primary reasons: (1) they have not been demonstrated at the larger scale necessary for power plant application; (2) the parasitic loads (steam and power) required to support CO_2 capture would decrease power generating capacity by approximately one-third; and (3) if successfully scaled up, they would not be cost effective at their current level of process development* (DOE/NETL Advanced Carbon Dioxide Capture Research and Development Program: Technology Update, May 2013, pp. 4 and 5).

> *Other major technical challenges associated with the application of currently available CO_2 capture technologies to coal-based power plants include energy and mechanical integration, flue gas contaminants, water use, CO_2 compression, and oxygen (O_2) supply for oxy-combustion systems. Therefore, further R&D of CO_2 capture technology is needed to ensure that this can be done cost-effectively* (DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update, May 2013, p. 6).

The May 2013 NETL report is more recent than the NETL reports that the EPA is relying upon to base its economic analysis for this proposed rule. Therefore, the NETL's assessment as to the current state of CO_2 capture technology is more up-to-date than the data that the EPA cites for its proposal. Nowhere does the EPA address the specific issues raised in the NETL report. The EPA should withdraw the proposed rule until the technical and economic issues raised by the NETL are addressed.

6. **EPA's reliance on government-subsidized projects to justify the proposed NSPS standard for coal-fired power plants is not appropriate. While some of these projects are proceeding with construction, economic feasibility of CCS in these projects is not demonstrated unless the EPA can show that the projects would have proceeded without the government funding. The examples of other government subsidies for the energy sector cited by the**

EPA are not relevant to the issue of EPA establishing BSER based on a project receiving federal funding.

While EPA is correct that government subsidies to reduce costs in the electricity generation sector are not unique to CCS (79 FR 1478), EPA's actions with the current proposal are unique. EPA is relying upon those government subsidies in an attempt to justify imposing a standard on coal-fired EGUs that is not economically feasible without those subsidies. All four of the CCS projects on power plants in the United States that the EPA cites in its proposal are receiving government subsidies specifically for the CCS aspects of those projects. Additionally, the Boundary Dam CCS project in Saskatchewan, Canada that the EPA cites is also receiving government funding. The EPA has not provided any examples of an active coal-fired power plant project under construction that is not receiving government assistance. The EPA attempts to rationalize the use of government-funded projects to establish BSER for this rulemaking by citing examples of other government subsidies for the nuclear power sector, domestic oil and gas production, coal exploration and development, and renewable energy generation. However, unless the EPA can point to a specific case in these examples where the EPA has established BSER based on technology directly derived from those subsidies, as is the case with CCS, then the examples given by EPA are not relevant to the fundamental action being proposed in this rulemaking. The apparent lack of identifiable EGU projects with CCS being developed or under construction that are not being subsidized by the government speaks not only to the lack of current technical feasibility, but also to the economic unreasonableness of such controls across the entire power sector.

7. **EPA's analysis of the costs of CCS is incomplete and is inconsistent with the approach typically used to evaluate the cost effectiveness of new emission control technologies.**

EPA claims that the proposed standard based upon IGCC and CCS is BSER and the associated costs are reasonable. EPA cites several D.C. Circuit Court decisions where the cost criteria of controls were raised. EPA notes the courts have used various terms such as "exorbitant costs," "greater than the industry could bear and survive," "unreasonable," and "excessive," to define whether a particular control option was the best system. EPA also notes that the D.C. Circuit has never invalidated a standard of performance on the grounds that it was too costly. EPA cites *Portland Cement Association v. Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973) as an example where high costs to meet an NSPS standard did not invalidate the rule because EPA had given the appropriate considerations to the "economic costs to the industry." EPA notes the cost of controls to meet the NSPS standard in *Portland Cement Association* were about 12 percent of the capital investment for the facility and an annual operating cost about 5-7 percent of the operating costs. Although the EPA references this case in which the capital cost and operating costs were evaluated and considered, EPA's analysis to support this rule doesn't discuss the capital cost of BSER control options, the percent of total costs that the potential BSER control options represent, or the annual operating costs. In addition, EPA's analysis does not address, evaluate, or discuss the dollar per ton of CO_2 removed cost associated with potential BSER controls, which is the typical analysis performed on control technologies considered by EPA.

EPA states that the cost of building and operating a coal-fired power plant that meets the proposed BSER is reasonable, because its cost of producing electricity is comparable to other power generation processes, including nuclear power plants. TCEQ, PUC, and RRC note that making a judgment about what would be a reasonable cost of electricity production is different than defining what would be a reasonable cost of controls. EPA is determining which electricity production processes will be employed in the future by ensuring that two of the three traditional base load generation processes, coal and nuclear, are unreasonably expensive, under the guise of establishing a BSER standard that is based upon an unreasonably expensive production technology, namely IGCC and CCS.

Another example of EPA not fully addressing the economic reasonableness of CCS is EPA's statement (79 FR 1481) that an alternative generation process is otherwise available, therefore the standard is economically reasonable. EPA states, "Moreover, even if requiring CCS adds sufficient costs to prevent a coal-fired plant from constructing in a particular part of the country due to lack of availability of EOR to defray the costs, or, in fact from constructing at all, a new NGCC plant can be built to serve the electrical demand that the coal-fired plant would otherwise serve. Thus, the present rulemaking does not prevent basic demand from being met, and thus does not have an adverse effect on the supply of electricity." This rationale is not a substitute for a true and complete analysis of the cost of CCS.

8. The proposed BSER standard is economically unreasonable and EPA's analysis does not appropriately consider the cost of ancillary factors such as pipelines, transportation of CO_2, and storage. The full cost of the proposed standards could substantially affect competition.

BSER is applied to a particular source and not the entire industry. Had EPA fully evaluated the costs of BSER, the proposed BSER standard based upon IGCC and CCS would have been rejected as economically unreasonable on its face without looking further at the effects on the industry. By itself, CCS is 30 to 50 percent of the total capital cost of a project, and the 30 percent parasitic loss resulting from CCS corresponds to a large annual operating cost. However, the proposed BSER is the proverbial "straw that breaks the camel's back" when considering the total cost of the proposed BSER along with other costs of controls in this source category.

If one were to follow EPA's rationale for not having to consider a pollutant-specific endangerment finding, because the justification and analysis is based upon source category, then one should also apply that rationale to evaluating total costs necessary to meet BSER for all pollutants, not just the newly added pollutants. CCS and other pollution controls for a PC unit would easily account for up to 80 percent of the total cost of a project. In terms of operating cost, CCS and other pollution control equipment combined can account for over 50 percent of the overall annual operating costs. Total costs, both capital and operating, of complying with BSER for all pollutants regulated in the subpart, including CCS controls and other existing required controls, are not economically reasonable.

Further, cost estimates provided by EPA related to CCS DOE/NETL studies from May 2010 through August 2012 do not include cost overruns that have been publicized for some of the projects EPA cites as currently under construction or under development. If EPA were to update the cost estimates to include cost overruns, and given the accuracy range of estimates of -15 to +30 percent from the center point cost in Table 6 on p. 1476 of the January 8, 2014 notice of proposed rulemaking, the actual cost could be beyond the cost criteria of BSER.

The TCEQ, PUC, and RRC also disagree with EPA's assertions that the cost of pipelines, transportation of CO_2, and storage is not a significant cost of CCS. TCEQ, PUC, and RRC also disagree with EPA's assertion (79 FR 1473) that, "nearly every state in the U.S. has or is in close proximity to formations with carbon storage potential…." TCEQ, PUC, and RRC note that EPA has issued GHG PSD permits that document the cost of pipelines to be a significant cost to a project that ultimately renders CCS economically unreasonable.

Furthermore, EPA has failed to include other costs associated with CCS, such as seismic studies, right-of-way costs, permitting, pore space ownership, liability, and water resources. There are numerous federally-funded projects involving the study of technical challenges to storing large volumes of carbon dioxide without leaks over hundreds of years. However, in addition to the technical challenges, there are regulatory, liability, and ownership issues associated with commercial-scale geologic storage of CO_2. These issues include, but are not limited to, long-term liability for injected carbon, legal issues if the CO_2 plume migrates underground across state boundaries, private property rights of owners of the surface lands above the injected CO_2 plume, ownership of the pore space, and public acceptance of commercial-scale geologic storage. As indicated by the Congressional Research Service (CRS), these "non-technical issues are not trivial, and could pose serious challenges to widespread deployment of CCS even if the technical challenges of injecting carbon dioxide safely and in perpetuity are resolved." CRS further stated that "[B]ecause of these issues and others, there are some indications that broad community acceptance of CCS may be a challenge."[1]

At a December 4, 2013 meeting with EPA's SAB, EPA air official Mr. Peter Tsirigotis argued that the NSPS establishing first-time CO_2 limits for utilities was no different from previous rules limiting sulfur emissions, in that neither addressed non-air impacts, such as how to dispose of scrubber sludge when establishing the sulfur emission control requirements. However, there were and are existing and established management and disposal technologies for scrubber sludge, unlike commercial-scale carbon dioxide sequestration. The logistics associated with the disposal of scrubber sludge are very different from the logistics and cost associated with the construction and operation of transportation pipelines along with the construction and operation of a commercial-scale geologic CO_2 storage facility.

Additionally, the TCEQ, PUC, and RRC disagree with EPA's conclusion (79 FR 1464) that the cost of BSER "could be passed on without substantially affecting competition." TCEQ, PUC, and RRC note that costs can be passed on more gradually and over a longer period of time in a regulated electric market than in a competitive electric market like Texas' Electric Reliability Council of Texas (ERCOT). Companies in a competitive electric market are more sensitive to additional costs, and are more likely to transfer those increased costs to electric consumers in the short term. Consequently, the ability to pass on the cost of BSER is likely to affect competition.

9. EPA's requirement that captured CO_2 must only be sent to a Class VI injection well or a Class II injection well that reports under Subpart RR will be a significant disincentive for enhanced oil or gas recovery well owners to accept utility-produced CO_2.

The TCEQ, PUC, and RRC are concerned that the requirement under 40 CFR Part 60 Subpart KKKK §60.5555 (d)(1) that requires captured CO_2 to be sent only to a facility reporting under 40 CFR Part 98, Subpart RR, will act as a disincentive for companies engaging in enhanced oil or

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[1] Carbon Capture and Sequestration: Research, Development, and Demonstration at the U.S. Department of Energy, CRS, February 10, 2014.

gas recovery (EOR) to actually accept and use utility-produced CO_2. Requirements under Subpart RR are much more stringent than those under Subpart UU, especially the requirement for Subpart RR wells to have an approved Monitoring, Reporting, and Verification (MRV) plan. The preamble for the Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide estimates costs under Subpart RR to be up to 537 times that of Subpart UU on a specific project basis [2]. It is instructive that Denbury Resources, a company that is significantly involved in enhanced oil and gas recovery and that is the future receiver of CO_2 from several ongoing CCS projects, states that:

> *Contrary to EPA's expectations, the proposed NSPS rule will foreclose – not encourage – the use of CO_2 captured by emissions sources in EOR operations. The reason is that compliance with Subpart RR will transform an EOR operation from a resource recovery operation into a waste disposal operation. Subpart RR compliance will create regulatory uncertainty and risk that will result in EOR operators avoiding the purchase of CO_2 that is subject to those rules. Operators will likely prohibit CO_2 suppliers from commingling "Subpart RR CO_2" with other CO_2 supplies being transported for EOR operations. Indeed, the EOR offtake agreements underlying the existing projects upon which EPA relies to show that CCS has been "adequately demonstrated" would not have been entered into if Subpart RR compliance had been required. In sum, requiring Subpart RR compliance by the EOR operator in order for the emitter to meet the NSPS standard will in fact foreclose the development of capture projects that would otherwise include EOR offtake agreements.*[3]

Further, it appears that EPA did not include the increased costs associated with Subpart RR compliance in its Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

The disincentives created by EPA for use of captured CO_2 in EOR activities is further exacerbated by EPA's recent Draft UIC Program Guidance on Transitioning Class II Wells to Class VI wells that gives broad discretion to the EPA to determine when an existing Class II EOR well should be regulated and permitted as a Class VI geosequestration well. The uncertainty of whether a Class II EOR well would be required to meet Class VI geosequestration well requirements as well as the cost, time, and long-term liability to transition a well from Class II to Class VI will be an additional significant disincentive for EOR well operators to accept utility-produced CO_2.

Finally, the TCEQ, PUC, and RRC completely disagree with the preamble statement that "[W]ells that inject carbon dioxide underground for enhanced oil or gas recovery may be permitted as UIC Class II or Class VI wells. However, the designation of the appropriate well class depends, principally, on the risks posed or changes in the risks posed to underground sources of drinking water by a specific injection operation" (79 FR 1482). Regardless of the language in the preamble, the language in 40 CFR §144.19 is clear. The Class VI UIC regulations as adopted require a determination as to whether or not the primary purpose of the injection of CO_2 is enhanced recovery. If the answer is yes, the well remains a Class II well. If the answer is no, then a determination must be made as to whether risks to underground drinking water sources have increased.

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[2] Federal Register Vol.75, No.230, December 1, 2010, Table 5 – Annualized Reporting Costs Per Project (2008$): Subparts RR and UU, p. 75073

[3] Paper by Denbury Resources "Subpart RR Flaws Preclude EPA's Reliance on CO2-EOR in the Proposed NSPS Rule."

10. EPA did not appropriately consider an efficiency-based standard for PC and circulating fluidized bed (CFB) units. EPA is attempting to apply an emission standard based on combined cycle turbines to a completely different source type of EGU.

EPA argues against efficiency improvements as a standard for coal-fired generators because, "…they do not provide meaningful reductions in CO_2 emissions from new sources" (79 FR 1435). However, EPA's NSPS for NGCC turbines is precisely a standard based solely upon efficiency. In fact, EPA calls NGCC units inherently low emitters. The heat recovery portion of a NGCC unit does not reduce emissions, but instead improves efficiency in producing electricity (or steam) by extracting heat from the exhaust gas. EPA has relied upon defining an efficiency level for NGCC units as BSER, which according to EPA will be the predominant type of EGU built in the foreseeable future, yet EPA rejects defining a standard based upon efficiency measures for coal-fired EGUs. EPA should have proposed an efficiency-based standard without CCS for coal-fired PC and CFB units.

EPA stated (79 FR 1470) "The level of the standard (1,100 lb CO2/MWh for coal-fired EGUs) is based on the emission reductions that can be achieved by an IGCC with a single-stage water-gas shift (WGS) reactor and a two-stage acid gas removal system." It is not appropriate to apply standards from one subcategorized emission source to other emission units in the same source category or in a different source category. A separate analysis and justification for standards applied to PC or CFB units should have been provided. No new PC or CFB units with CCS have been identified by EPA. The PC units EPA identified with CCS are retrofits on existing units. IGCC should be either listed as a separate source category or the BSER standard for IGCC should be listed in Subpart KKKK, because the source of emissions is from the combined cycled turbine and not the gasifier. An IGCC is a combined cycle turbine that is fired with a fuel that has been gasified upstream of the combined cycle turbine. The turbine portion of an IGCC unit can burn natural gas when the gasifier is not producing syngas. Additionally, the syngas can be placed in a pipeline for sale and does not have to be burned as fuel in the combined cycle portion of the IGCC unit. Combined cycle turbines generally produce more electrical output per the same amount of fuel burned in an EGU that utilizes a simple steam cycle to produce electricity, because the combined cycle uses the steam cycle and a mechanical cycle to produce electricity. The claim that NGCC is inherently lower-emitting is completely a function of the basis of the standard that EPA chose, which is an output based standard of lb CO_2/MWh. For example, a gas turbine in simple cycle mode will emit the same emissions (on a pound per hour, ton per year, and lb of CO_2/ MMBtu heat input basis) as the identical gas turbine in the combined cycle mode, except the combined cycle turbine will produce more electricity and appear to emit less, because of the basis of the standard. EPA is stacking both CCS and an "inherently lower emitting unit," a combined cycle turbine, to establish an output based emission standard that EPA is erroneously applying to a completely different source type of EGU (subcritical, supercritical pulverized coal boilers, and circulating fluidized bed units).

11. For certain unit types, EPA's proposed BSER standard is not achievable with partial CCS.

EPA's claim that the proposed standard is based upon partial CCS is misleading. EPA states, "The level of the standard (1,100 lb CO_2/MWh for coal-fired EGUs) is based on the emission reductions that can be achieved by an IGCC with a single-stage WGS reactor and a two-stage acid gas removal system." EPA also acknowledges that a subcritical unit, a supercritical unit, and an IGCC unit without CCS would emit at 1800, 1700, and 1450 lb CO_2/MW respectively. A subcritical or supercritical unit would have to capture roughly double the amount of CO_2 as an IGCC in order to meet the standard, which means that the standard as it would apply to subcritical and supercritical EGUs is not based upon the degree of partial CCS and consequently would be prohibitively more expensive. EPA's analysis in the proposed rule claims that as the percent of CCS increases, the economic viability decreases.

D. Impact to Reliability, Affordability, Public Health, and the Economy.

1. **EPA's analysis for Executive Order 13211 is not adequate, and a more thorough analysis is needed of the long-term impacts of the proposed GHG NSPS rule on energy supply, distribution, and use.**

EPA's analysis statement for Executive Order 13211 is simply that the rule is not expected to have a notable impact on emissions, costs, or energy supply decisions for the affected electric utility industry, which isn't adequate. This assumption of no impact for the purposes of Executive Order 13211 is based on the same assumption that EPA uses in other aspects of the proposed rule; EPA's IPM results indicate that no new coal-fired generation will be built through 2020 even without the proposed rule in place. EPA has an obligation to perform a fully-reasoned analysis of the impact of their regulatory actions on the nation's electrical power system. EPA must consider the possibility that their IPM projections are wrong, and perform a thorough analysis of the impact to the national electricity supply, costs, and distribution if natural gas prices are higher than projected and new coal-fired generation is no longer an option for the electric power industry.

Earlier this year, EPA announced that it is considering whether to adopt an economy-wide model to evaluate proposed air regulations. Under that model, EPA would consider a broad range of a regulation's potential economic impacts, including impacts on energy prices and industry and labor markets. TCEQ, PUC, and RRC agree that such an endeavor is prudent and urge EPA to withdraw the proposed rules until such an economy-wide analysis has been completed and taken into consideration.

2. **Decreased fuel diversity in the electric power generation industry will have adverse consequences for affordable and reliable electric power in the nation. Decreased affordability and reliability of the power system poses risks to public health, safety, and to the economy.**

Decreasing the fuel diversity in the electric power generation industry and relying too heavily on one particular fuel source will have adverse consequences on the national electrical power system, both in terms of reliability and affordability. Recent gas delivery issues in northern states have shown that an over-reliance on one fuel type can lead to severe short-term price dislocations, and in some cases, curtailment of generation due to fuel deliverability issues. An unreliable or unaffordable power system would have serious effects on public health and safety, especially for vulnerable low-income populations. Just a few examples of the effects of an unreliable power system include a lack of adequate lighting, heating, or cooling for homes, and lack of appropriate refrigeration, cooking, or sanitation facilities. All of these conditions could lead to injury or disease. Essential service providers such as hospitals, police departments, water and sewer utilities, fire departments, and others also depend on having reliable electricity to fulfill their necessary duties that keep people alive and protect citizens against danger.

Businesses in Texas and across the nation are critically dependent on the reliable delivery of reasonably-priced electricity to support their operations. An unreliable or excessively costly power system would have major adverse impacts on productivity and business revenue.

3. **EPA should not use the Office of Management and Budget's (OMB) Revised Social Cost of Carbon Estimates in the Cost/Benefit Analysis.**

In Section 5.7 of the RIA, EPA uses the OMB's revised estimates for the Social Cost of Carbon (SCC) in estimating the cost and benefits of the subject regulatory proposal for new electric generating units. The TCEQ provided comments to OMB regarding their Technical Support Document: Technical Update of the Social Cost of Carbon (SCC) for Regulatory Impact Analysis under Executive Order No. 12866 published in the Federal Register on November 26, 2013. Given that OMB has requested comments on the SCC estimates, TCEQ, PUC, and RRC believe it is inappropriate for EPA to use the revised estimates in the 111(b) rulemaking as it deprives stakeholders the opportunity to comment on the final version of the OMB guidance. Notwithstanding TCEQ's objection to the use of the OMB guidance in the 111(b) rulemaking, TCEQ, PUC, and RRC offer the following further comments on EPA's use of the SCC estimates in the RIA.

The assumptions, both scientific and economic, of the Interagency Working Group that developed the initial SCC estimates are largely unknown and were not subject to independent peer review as called for by the Information Quality Act and OMB's own internal guidelines. The TCEQ, PUC, and RRC strongly recommend that the SCC estimates not be used in the 111(b) rulemaking until the entire process and data used in developing the SCC estimates are subjected to thorough, independent, external peer review.

The models used to derive SCC estimates suffer from considerable uncertainty and speculation in critical inputs including the amount of future carbon emissions, the impact of those emissions on the climate, and the monetization of those impacts. The uncertainty associated with temperature increases is just one example. The models used by the United Nations Intergovernmental Panel on Climate Change (IPCC) have not predicted the current stoppage of global warming, as evidenced by global temperature measurements, over the last 15 years. To the extent that IPCC model data was used in developing the SCC estimates, their use for the short term is clearly circumspect and extrapolation of temperature increases and its impacts over a longer modeling time horizon is of even greater uncertainty.

A key variable in estimating the SCC is the discount rate. OMB Circular A-94 states that a discount rate of 7 percent should be used as a base case for regulatory analysis as a default position while acknowledging that in some cases, other discount rates may be appropriate. OMB Circular A-4 states that "For regulatory analysis, you should provide estimates of net benefits using both 3 percent and 7 percent." The impact of the use of different discount rates can be significant. In the revised Technical Support Document, the social cost of carbon for 2050 is $97/metric ton of CO_2 using a 2.5 percent discount factor while it is $26/metric ton of CO_2 using a 5 percent discount factor. EPA should include an analysis using a discount rate of 7 percent, as suggested by OMB.

The TCEQ, PUC, and RRC understand that the SCC estimates are based on the global benefits of CO_2 reductions vs. the benefits that would occur domestically in the United States. Given that the SCC estimates will be used to compare benefits to the domestic costs of a regulatory action, the SCC estimates should be directly related to domestic benefits. TCEQ, PUC, and RRC note that OMB Circular A-4 states that "analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional." In the 2010 Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, the Interagency Working Group concluded that a global measure of benefits from reducing U.S. emissions is preferable in order to address the global nature of climate change and to show that international action is necessary since "even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change." The TCEQ, PUC, and RRC disagree that a global measure is preferable in that the public has the right to know the domestic benefits vs. the domestic costs of a regulatory action. The use of a global SCC could show that benefits exceed costs when they actually may not provide any net benefits for the United States.

In addition, the Interagency Working Group determined that the models were currently inadequate to determine region- or country-specific estimates of the SCC, but "that a range of values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects." This range was based on very generalized key parameter assumptions using a 2.5 or 3 percent discount rate (which in itself is a subjective and questionable rate) or alternatively by proportionally determining benefit by the U.S. share of gross domestic product. The Working Group itself acknowledged that this range was highly speculative. The TCEQ, PUC, and RRC submit that the method of translating global benefits to domestic benefits is so speculative at this time that its use is not appropriate.

In summary, EPA should not use the SCC estimates in the current 111(b) rulemaking project until there has been a complete and thorough independent peer review of the process and model data.

4. **The ERCOT grid in Texas is unique in the United States in that it is wholly intra-state and essentially isolated from the two other U.S. grid interconnections. Additionally, regulatory changes can have a different impact on market prices and reliability in the ERCOT region than in other regions of the country due to the energy-only nature of the ERCOT market.**

i. The federal EPAct05 recognized the importance of ensuring reliability of electric grids by creating an Electric Reliability Organization ("ERO"). The ERO function is performed by the North American Electric Reliability Corporation (NERC), which oversees a vast set of reliability standards that govern operations and planning and are designed to ensure the reliability of the bulk power system. Under the NERC reliability construct, ERCOT is designated as both the Reliability Coordinator and the Balancing Authority, and as a Transmission Operator for the ERCOT Region. ERCOT is also registered for several other functions, including the key planning function of Planning Authority. The Texas Reliability Entity, Inc. monitors and enforces compliance with reliability standards for NERC, develops regional standards, and monitors and reports on compliance with the ERCOT Protocols.

Figure 2. The ERCOT Region covers most of Texas and includes Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, Abilene and the Rio Grande Valley.

ii. The ERCOT grid is unique in the United States in that it is wholly intra-state and essentially isolated from the two other U.S. grid interconnections (the Western and the Eastern Interconnections). The ERCOT grid is not synchronously connected outside of the state, and there is limited ability for the ERCOT region to import or export electricity. There are 5 asynchronous ties between ERCOT and other interconnections: two linking ERCOT and the Eastern Interconnection (with a combined capacity of 820 MW), and three linking ERCOT and the electrical grid in Mexico (with a combined capacity of 286 MW). Flows on these asynchronous ties are scheduled by market participants. ERCOT can request support from neighboring regions during grid emergency events. Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT region is an island that must independently ensure its own electric reliability.

iii. Generating capacity in the ERCOT region consists of a mix of generation technologies, fueled by coal (both lignite and sub-bituminous), natural gas, nuclear, wind, and other sources. Almost forty percent of the energy generation in the ERCOT region comes from coal.

iv. Ensuring reliability requires a constant balance between supply and demand. Unlike gas or water, electricity cannot be efficiently stored in large quantities – it must be generated to meet demand on a real-time basis. This means generation and transmission operations must be monitored in real time, 24 hours a day, to ensure a reliable and continuous flow of electricity. It is critical that ERCOT has enough generating capacity to meet demand at every given moment.

v. ERCOT must have and maintain adequate installed capacity to cover the forecasted load on the system as well as to ensure reliability in case of events such as higher-than-projected demand (e.g., due to extreme temperatures) or unplanned generation outages (e.g., due to mechanical breakdowns), and limited generation from variable resources. Reserve margins reflect a snapshot of existing and currently planned generation resources in excess of forecasted peak demand as a percent of that forecasted peak demand. Having a sufficient reserve margin is necessary to ensure reliability in the case of these events that are outside of normal planning assumptions. In November 2010, the ERCOT board approved a minimum planning Reserve Margin target of 13.75 percent for the ERCOT region, based on the generally accepted industry criteria of limiting firm load shedding due to supply inadequacy to once every ten years.

vi. ERCOT must also maintain a sufficient amount of generating capacity on-line in each hour to serve the load at that time, cover instantaneous variation in load and to instantaneously replace the generation from any generating units which suffer an unexpected maintenance disruption and are immediately disconnected from the electrical grid. This capacity is commonly referred to as operating reserves. When sufficient generation is not available to meet these requirements, ERCOT institutes a progressive series of emergency steps to address the problem. The initial stages focus on maximizing the use of supply resources and the later stages focus on the utilization of ancillary services provided by demand response. With respect to maximizing supply options, ERCOT notifies resource owners to make all generation capacity available and requests assistance from other grids. ERCOT's ability to import power from other regions is physically limited by the capacity of its direct current (DC) ties, which is approximately 1,106 MW. However, ERCOT is not entitled to any of that capacity. ERCOT has the right to request assistance, but there must be supply available in the adjoining region. In addition, there must be transmission capacity available to accommodate the import.

vii. ERCOT has two demand-response programs that can be utilized in grid emergencies to reduce the amount of load connected to the grid in order to balance load with available generation. ERCOT typically procures as much as 1,400 MW of Load Resources and approximately 450 MW of Emergency Response Service (ERS); these programs are utilized by ERCOT in the second and third stages of a grid emergency to maintain system stability. When all of these operational tools are exhausted, ERCOT implements firm load shedding through the use of rotating outages. The progression of these stages is indicative of increased system stress related to increasing demand against decreasing operating reserve margins.

viii. At any given time, available generating capacity is typically less than the theoretical maximum, for a variety of reasons. For example, all plants have planned and unplanned maintenance outages that can render them unavailable. Available generating capacity in ERCOT changes daily and seasonally. It is lowest in the spring and fall when many plants are scheduled to be off-line for maintenance outages. On average, approximately 10,000 MW of generation capacity is unavailable during the spring and fall months due to scheduled periodic maintenance requirements. Similarly, approximately 4,000 MW of generation capacity is typically unavailable at any given moment due to unplanned forced maintenance outages.

ix. ERCOT typically experiences peak demand in the summer season (June – September). As shown in Figure 3 below, demand has been consistently increasing in Texas and is projected to steadily increase through 2023.

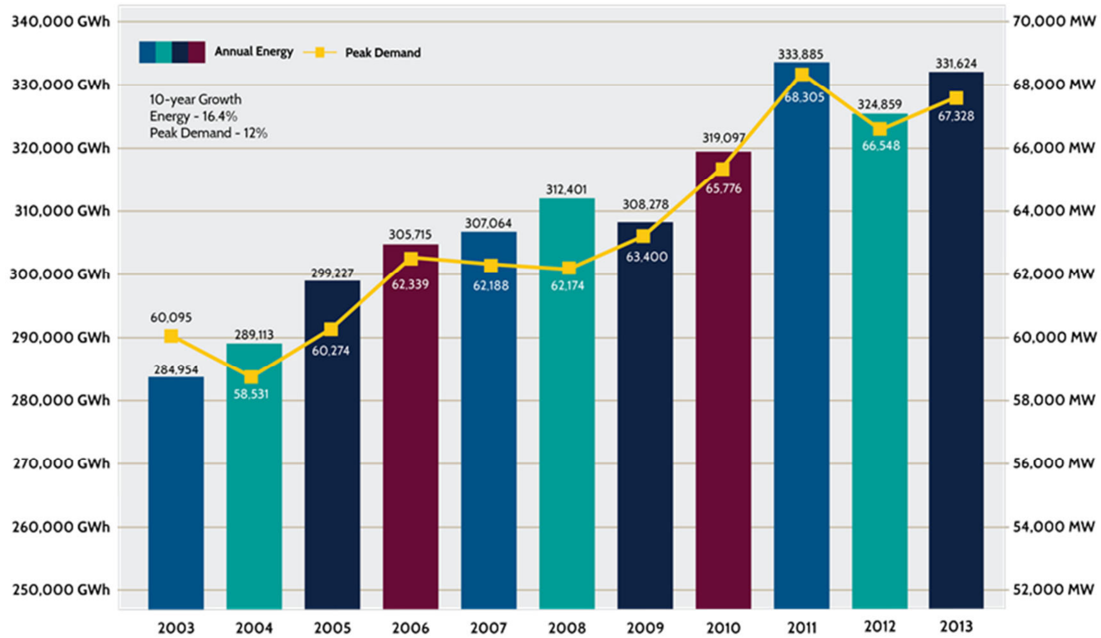

Figure 3 – ERCOT's Historical Load Data

x. ERCOT administers the planning function for the ERCOT region. This function forecasts future peak demand and establishes transmission and supply requirements over the relevant period to maintain reliability of the electric grid. However, the ERCOT region, under state law, employs a competitive market construct for generation supply. In this environment, generation owners bear the risk of investment and decide when and where to build new generation, and whether to retire or idle existing generation, based on market conditions. ERCOT, the regulated transmission and distribution utilities (which provide only "wires" service and do not own or operate generation facilities), and the PUC do not have the authority to order generators to maintain or to add generating capacity. Rather, the ERCOT market is designed to provide financial signals to competitive generation companies to ensure adequate generation capacity.

xi. The ERCOT market is singular in that generating plants are paid only for the energy and the operational ancillary services they provide (commonly referred to as an energy-only market). As a result, regulatory changes can have a different impact on market prices and reliability in the ERCOT region than in other regions of the country.

xii. This ERCOT energy-only market design has proven itself to be supportive of robust competition between generating technologies and fuel sources. A result of this market design is also that older, uncompetitive generating units tend to be retired more quickly, as units that do not operate are not able to earn any revenues. Reserve margins in ERCOT have tended to be at or even slightly below the target reserve margin of 13.75 percent for the past few years.

xiii. In the ERCOT market, generation unit development decisions are made by independent investors, based on their analyses of market conditions and expectations of return on investment. As such, new investment in generating units will be made after the general market becomes aware of a system need. Regulatory changes that result in significant changes in the market must have sufficient lead time so that the impacts can be assessed by the market and new investment can be made.

E. EPA Setting Energy Policy.

1. This proposal effectively takes away an energy generation option for utilities and states yet EPA does not have the authority to set energy policy for the United States.

By EPA's own estimate, no new coal-fired power plants will be built in the United States in the near future due to the economics of coal and natural gas prices. EPA determined that energy prices would not increase because no more than a few new coal fired projects with partial CCS, as BSER, are expected to be built. The model relied upon for this assessment, IPM, does not forecast any new coal-fired EGUs through 2020, and forecasts negligible CO_2 reductions as a result through 2022. However, in practical effect, EPA is ending the coal-fired power generation option in the future, regardless of subsequent fuel prices and market conditions. The proposed CO_2 emission standard for EGUs is not fuel neutral. EPA admits that no new coal-fired EGUs will be built in the near future and those that can be built to meet the standard, must rely on technology that is not yet technically and economically feasible. This unprecedented approach effectively bars utilities from establishing a diverse energy portfolio necessary to meet use demands. FCAA section 111 does not give EPA the authority to establish air regulations that make EPA the energy policymaker for the country.

F. Implications for PSD and Title V Programs.

1. TCEQ interprets its recently-adopted PSD rules will apply the Tailoring Rule thresholds even after EPA promulgates this NSPS.

This re-proposal, if finalized, would regulate CO_2 under section 111 for the first time, and under federal PSD and Title V regulations, regulation of a pollutant under NSPS triggers applicability of PSD. In comments on the April 13, 2012, proposal, several states, including Texas, expressed concern that revisions to State Implementation Plan (SIP)-approved PSD programs incorporating the tailored GHG thresholds may not apply to a pollutant once it is regulated under section 111. EPA states the proposal should not require SIP revisions in order for the Tailoring Rule thresholds to continue to apply. EPA takes the position that the tailoring rule thresholds will continue to apply once the NSPS is promulgated, even though those thresholds were not incorporated into the portion of the PSD definition of "regulated NSR pollutant" that refers to section 111 pollutants. According to EPA's interpretation, the definition of "major stationary source" itself already incorporates the Tailoring Rule thresholds, and not just through one prong of the term "'regulated NSR pollutant."

TCEQ recently adopted GHG PSD and Title V program rules in order to obtain authority to issue PSD and Title V permits for GHGs at the EPA-tailored thresholds; and to have the currently imposed GHG PSD FIP in Texas rescinded. These recently-adopted rules are crafted in a similar fashion so that GHGs specifically are subject to regulation under PSD and Title V at the higher thresholds, even if these pollutants are subsequently regulated under an NSPS. Thus, TCEQ can interpret its SIP, once approved, to apply the Tailoring Rule thresholds to GHGs, including CO_2.

2. The proposed rules preclude some PSD permit applicants from making an economic reasonableness argument.

EPA's adoption of the proposed NSPS would preclude applicants for PSD permits for coal-fired power plants without CCS from making an economic reasonableness argument, because the proposed NSPS establishes a floor for best available control technology (BACT). FCAA section 169(3) defines "best available control technology" which is a requirement to obtain a permit issued under FCAA section 165. The definition of BACT also includes the following, "In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act." To date, no new coal-fired EGUs seeking PSD permits for GHGs have been required to install CCS, because that technology has been rejected as being economically unreasonable. EPA suggests that CCS will become economically reasonable in the future, because control costs usually decline over time, but it is unknown how far into the future that will be, and in the meantime a permit applicant for a PSD permit for a coal-fired EGU would be forced to meet a standard that would require CCS which is currently cost-prohibitive.

3. TCEQ, PUC, and RRC support a rule that provides the states with flexibility in crafting their individual fee programs, and acknowledges EPA's intention to not revise fee schedule flexibility through this proposal.

EPA requested comment on the proposed changes to the Title V fee requirements in 40 CFR Part 70. TCEQ, PUC, and RRC support a rule that provides the states with flexibility in crafting their individual fee programs, and acknowledges EPA's intention to not revise fee schedule flexibility through this proposal. Part 70 requires state operating permit programs to collect fees sufficient to cover the costs of the program. As EPA states in the preamble (79 FR 1491), "...neither the Act nor Part 70 specifies the details of how those fees must be charged to particular sources in their fee schedules." In 2011, TCEQ revised its emissions fee rule to provide for an adjustable base rate in its fee calculation. This rule allows the commission to more readily adjust the fee based on current program costs and needs. TCEQ, PUC, and RRC support the exclusion of GHGs from fee calculations. As part of the GHG PSD and Title V permitting rule adopted in March 2014, TCEQ is excluding GHGs from fee calculations. EPA recognized in the Tailoring Rule and this proposal, that assessing fees on GHGs could lead to excessive fees from sources; and that fees on non-GHG pollutants from Title V sources should be sufficient to cover program costs. The additional flexibility in the fee calculation in TCEQ rules will also allow the commission to readily respond to increases or decreases in program resource needs.

G. Rationale for Proposed Standards for New Sources.

1. EPA's rationale for not performing a separate, pollutant-specific endangerment finding for GHG emissions from EGUs is inadequate.

EPA's logic is flawed in that the agency assumes that because an existing source category is already listed and because sources in that category emitted a particular pollutant, that source category must cause or contribute to an endangerment of public health and welfare for a different pollutant. The purpose of identifying source categories is to establish appropriate standards of performance on a pollutant-specific basis for those source categories. Note that a standard of performance is defined as "...a standard *for emissions of air pollutants* (emphasis added) which reflects the degree of emission limitation achievable through..." One can conclude that since the standard is on a pollutant-specific basis, the determination of the endangerment consideration must also be on a pollutant-specific basis.

Further, GHGs are newly regulated pollutants under the FCAA, have never been evaluated for impacts on a source category by source category basis, and are wholly different from criteria pollutants generally regulated from stationary sources. These pollutants react differently in the atmosphere than any other type of pollutant and thus do not endanger public health or the environment in the same immediate or localized fashion. Therefore, a new and distinct endangerment finding should be conducted. For this same reason, EPA should not rely on the 2009 Endangerment Finding it made for mobile sources as a 'rational basis' for a finding of endangerment caused by emissions of GHGs from a specific category of stationary sources. EPA simply proposes in the current rule that CO_2 emissions from fossil fuel-fired EGUs cause or contribute significantly to GHG air pollution, because GHG emissions from existing EGUs account for almost one third of all U.S. emissions of GHGs, and EGUs are the single largest stationary source category of GHGs. This assertion is not a substitute for a properly-conducted endangerment finding. TCEQ, PUC, and RRC are not aware of any endangerment determination made by EPA, in this proposal or elsewhere, directly considering the effects of GHGs from EGUs. Additionally, EPA has not presented any analysis tying emissions from the *new* (emphasis added) EGUs in the new source category directly to any health effects related to GHGs. In fact, EPA is claiming that no new Subpart Da units will be built and EPA makes no attempt to quantify new emissions from NGCC units. As already stated in comment A.2 above, if the "overriding purpose" for section 111 is to prevent new pollution, EPA has proposed an admittedly insufficient standard regulating sources that may never be built.

EPA's 'rational basis' argument for regulating GHG from new fossil-fueled EGUs is flawed. EPA does not concede that section 111 requires an endangerment finding to justify regulating GHG from fossil-fired EGUs, but instead claims EPA is only required to "have a rational basis for promulgating standards for GHG emissions from electric generating plants…" EPA concludes, "…that even if section 111 requires an endangerment finding, the rational basis described in today's action would qualify as an endangerment finding as well." EPA's play on words, substituting "rational basis" for "reasonably anticipated" is not founded in statute. EPA provides neither an endangerment finding nor a rational basis for regulating GHG from new EGUs. EPA claims their rational basis for promulgating standards under section 111 for new electric generating plants is that EPA has already determined that GHG emissions may reasonably be anticipated to endanger public health and welfare, "…because electric generating plants, as an industry, constitute, by a significant margin, the largest emitters in the inventory." There are several problems with this rationale. First, the quantity of emissions from existing sources within a given source category has nothing to do with emissions from new units that are in the same source category. The dose-response reasoning prevalent in almost all EPA regulations seems to have been abandoned by EPA in this proposed NSPS. EPA is essentially saying that any new emissions from EGUs would be harmful, which negates the rationale for even having a standard, since GHG are a global pollutant and other nations will emit GHG regardless of GHG emitted within the United States.

H. Startup, Shutdown, and Affirmative Defense Provisions.

1. **EPA should provide an appropriate standard for startup and shutdown emissions.**

EPA proposed that NGCC units include startup, shutdown, and reduced load (SSRL) operation emissions on an annual basis in meeting the proposed NSPS performance standard. The TCEQ, PUC, and RRC recommend that SSRL related emissions from NGCC units be excluded from meeting the proposed numerical standard and that work practices be prescribed as BSER during SSRL. Alternatively, TCEQ, PUC, and RRC recommend that periods of SSRL operation be considered simple cycle operating hours not subject to the limitation.

TCEQ, PUC, and RRC note that the NGCC standard is not based upon an add-on control technology to limit CO_2 emissions, but is instead based upon an efficiency of producing power. The efficiency of the gas turbine will depend upon many factors including ambient temperature, humidity, and operating load. Most NGCC units will also have to rely upon power produced by the steam turbine to meet the proposed standard. TCEQ, PUC, and RRC are aware that an NGCC unit may not be able to comply with the proposed numerical standards during SSRL operations and that compliance with the proposed BSER standard may simply become a function of where the turbine is physically located, which particular electrical grid the turbine supports, and how the NGCC unit is operated. EPA should withdraw or delay the adoption of the rule until an appropriate standard or method for evaluating compliance during SSRL operation has been provided.

2. **The proposed rules should be revised to enable the EPA to allow state rules for affirmative defense that are EPA-approved as part of a SIP to be used in lieu of the federal procedures.**

This flexibility would eliminate duplicative or potentially even conflicting requirements for both state agencies and regulated entities. If the rule is not revised, TCEQ would like assurance that the owner or operator could use SIP affirmative defense provisions in state rules in lieu of affirmative defense provisions in the proposed NSPS. Texas rules under 30 Texas Administrative Code (TAC) Chapter 101 provide for emissions events reporting requirements that are substantially the same as the proposed rules. Emissions events are any upset event or unscheduled maintenance, startup, or shutdown (MSS) activity, from a common cause that results in unauthorized emissions of air contaminants from one or more emissions points at a regulated entity.[4] Generally, an upset is the functional equivalent of a malfunction. If the SIP - approved rules can be approved as an alternative affirmative defense for this NSPS, consideration may be given to the Texas criteria describing "the percentage of a facility's total annual operating hours during which emissions events occur" in lieu of the frequency in EPA's proposed affirmative defense criteria.

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[4] *See* 30 Tex. Admin. Code, Chapter 101, General Air Quality Rules, Subchapter A, § 101.1(91), (109) and (110). Unscheduled or unplanned activities are activities with unauthorized emissions that are expected to exceed a reportable quantity (RQ), a scheduled MSS activity is an activity that the owner or operator of the regulated entity whether performing or otherwise affected by the activity, provides prior notice and a final report as required by § 101.211; the notice or final report includes the information required in TCEQ rule 30 § 101.211; and the actual unauthorized emissions from the activity do not exceed the emissions estimates submitted in the initial notification by more than an RQ. For activities with unauthorized emissions that are not expected to, and do not, exceed an RQ, a scheduled MSS activity is one that is recorded as required by § 101.211. Upset events are unplanned and unavoidable breakdowns or excursion of a process or operation that results in unauthorized emissions. A scheduled MSS that was reported, but had emissions that exceeded the reported amount by more than a reportable quantity due to an unplanned and unavoidable breakdown or excursion of a process or operation is an upset event.