EXHIBIT 1

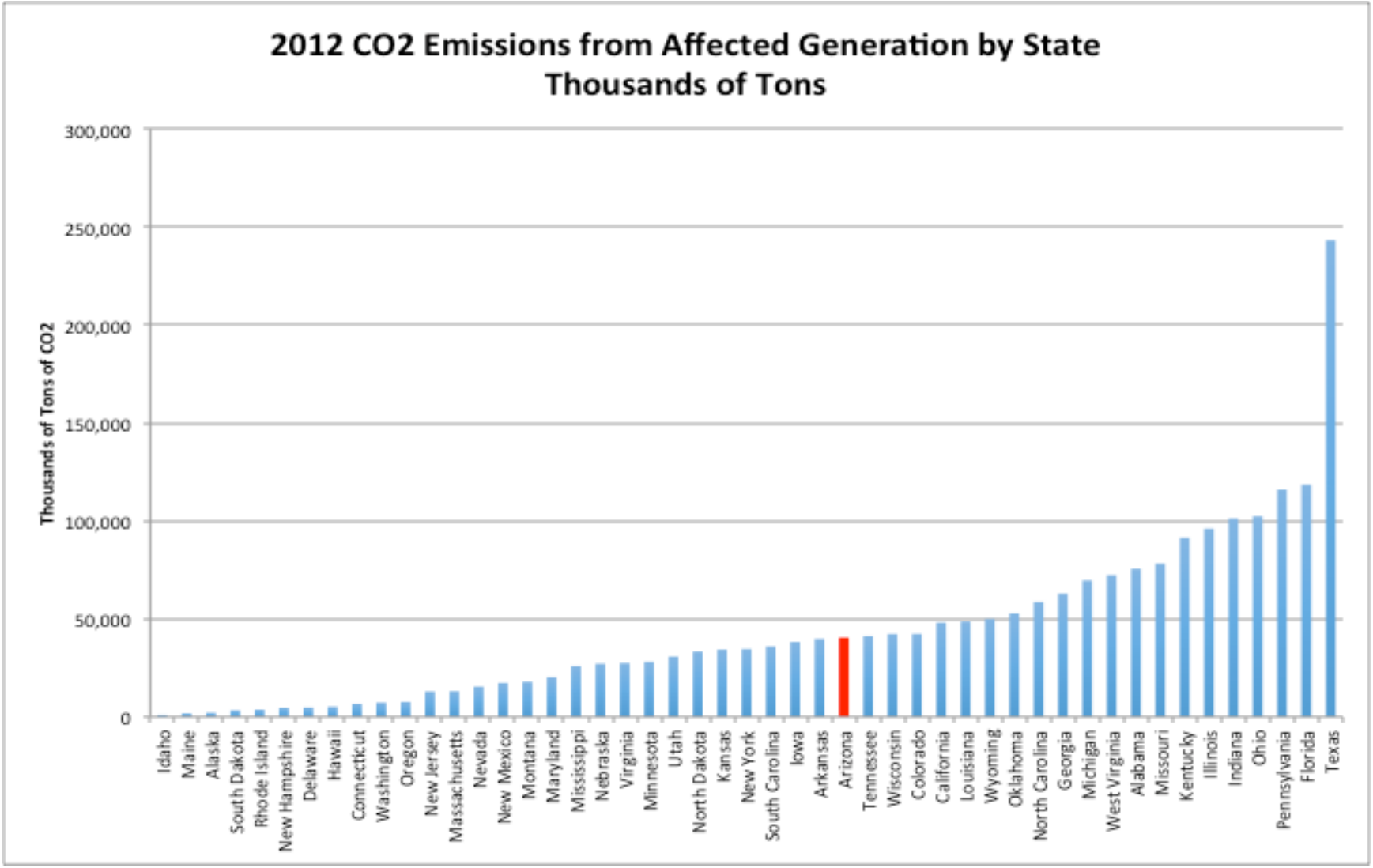

2012 CO2 Emissions from Affected Generation by State
Thousands of Tons
Thousands of Tons of CO2
300,000
250,000
200,000
150,000
100,000
50,000
0
Idaho
Maine
Alaska
South Dakota
Rhode Island
New Hampshire
Delaware
Hawaii
Connecticut
Washington
Oregon
New Jersey
Massachusetts
Nevada
New Mexico
Montana
Maryland
Mississippi
Nebraska
Virginia
Minnesota
Utah
North Dakota
Kansas
New York
South Carolina
Iowa
Arkansas
Arizona
Tennessee
Wisconsin
Colorado
California
Louisiana
Wyoming
Oklahoma
North Carolina
Georgia
Michigan
West Virginia
Alabama
Missouri
Kentucky
Illinois
Indiana
Ohio
Pennsylvania
Florida
Texas

EXHIBIT 2

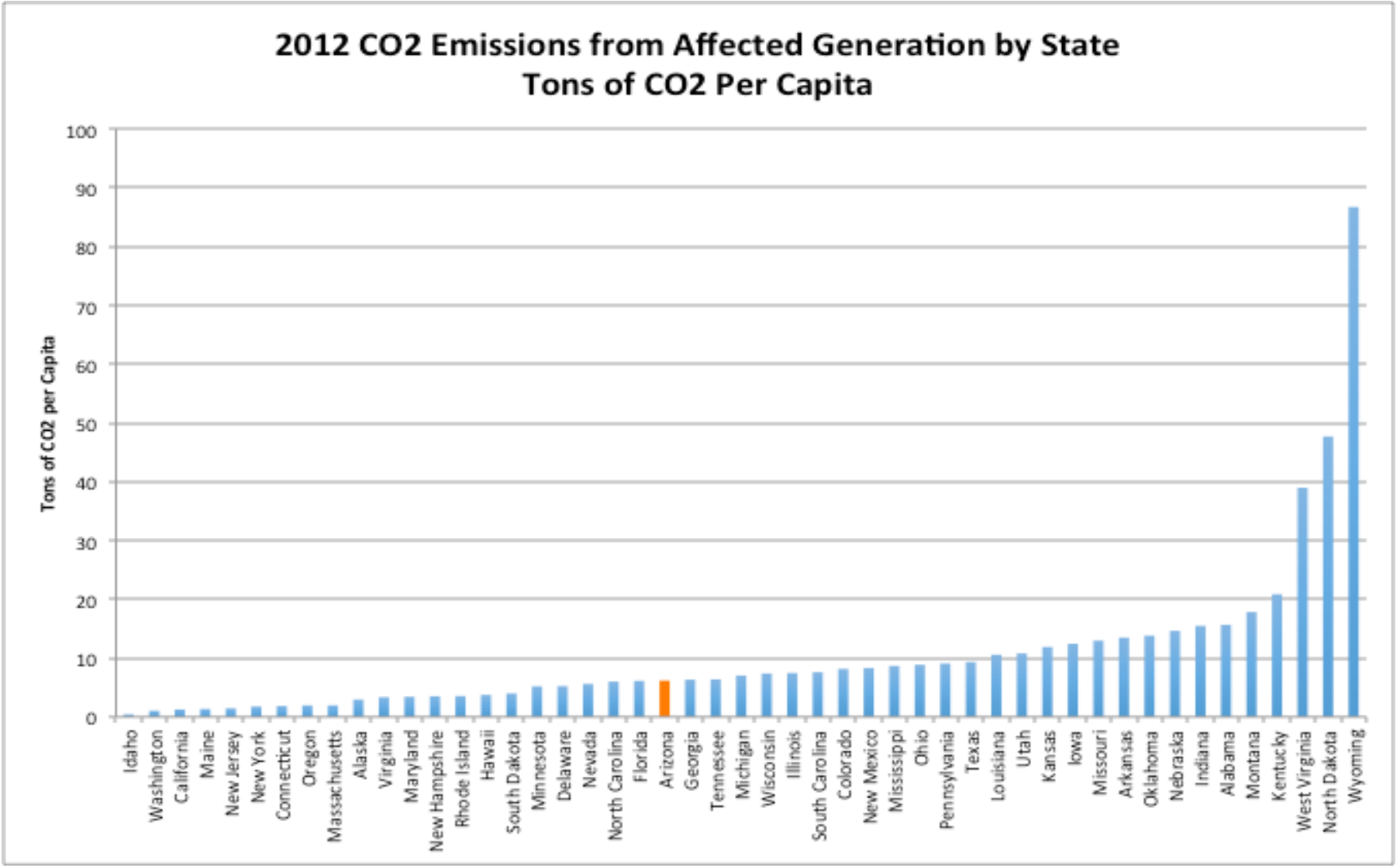

2012 CO2 Emissions from Affected Generation by State
Tons of CO2 Per Capita
Tons of CO2 per Capita
100
90
80
70
60
50
40
30
20
10
0
Idaho
Washington
California
Maine
New Jersey
New York
Connecticut
Oregon
Massachusetts
Alaska
Virginia
Maryland
New Hampshire
Rhode Island
Hawaii
South Dakota
Minnesota
Delaware
Nevada
North Carolina
Florida
Arizona
Georgia
Tennessee
Michigan
Wisconsin
Illinois
South Carolina
Colorado
New Mexico
Mississippi
Ohio
Pennsylvania
Texas
Louisiana
Utah
Kansas
Iowa
Missouri
Arkansas
Oklahoma
Nebraska
Indiana
Alabama
Montana
Kentucky
West Virginia
North Dakota
Wyoming

EXHIBIT 3

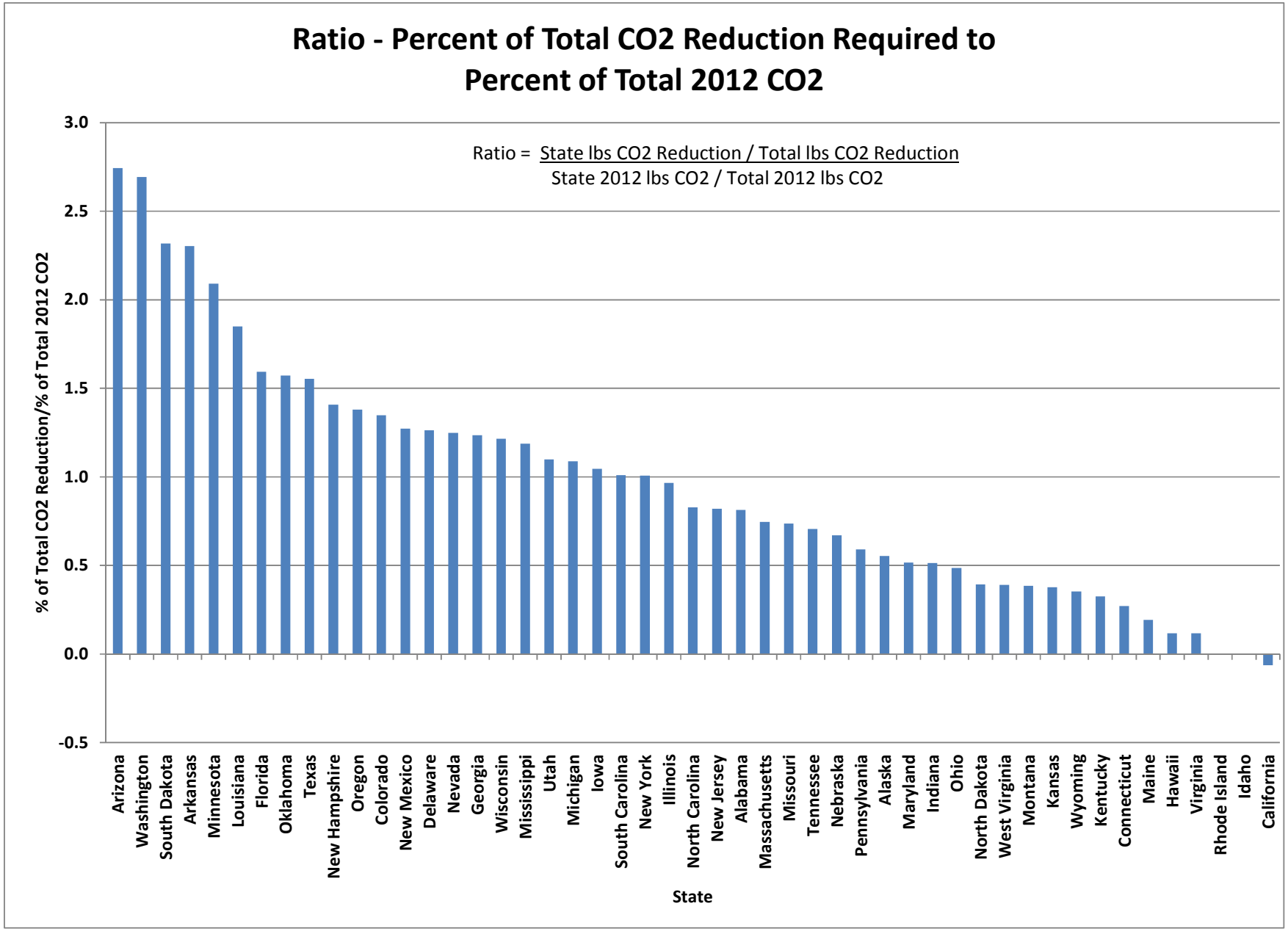

Ratio - Percent of Total CO2 Reduction Required to Percent of Total 2012 CO2
Ratio = State lbs CO2 Reduction / Total lbs CO2 Reduction
State 2012 lbs CO2 / Total 2012 lbs CO2
% of Total CO2 Reduction/% of Total 2012 CO2
3.0
2.5
2.0
1.5
1.0
0.5
0.0
-0.5
Arizona
Washington
South Dakota
Arkansas
Minnesota
Louisiana
Florida
Oklahoma
Texas
New Hampshire
Oregon
Colorado
New Mexico
Delaware
Nevada
Georgia
Wisconsin
Mississippi
Utah
Michigan
Iowa
South Carolina
New York
Illinois
North Carolina
New Jersey
Alabama
Massachusetts
Missouri
Tennessee
Nebraska
Pennsylvania
Alaska
Maryland
Indiana
Ohio
North Dakota
West Virginia
Montana
Kansas
Wyoming
Kentucky
Connecticut
Maine
Hawaii
Virginia
Rhode Island
Idaho
California
State

EXHIBIT 4

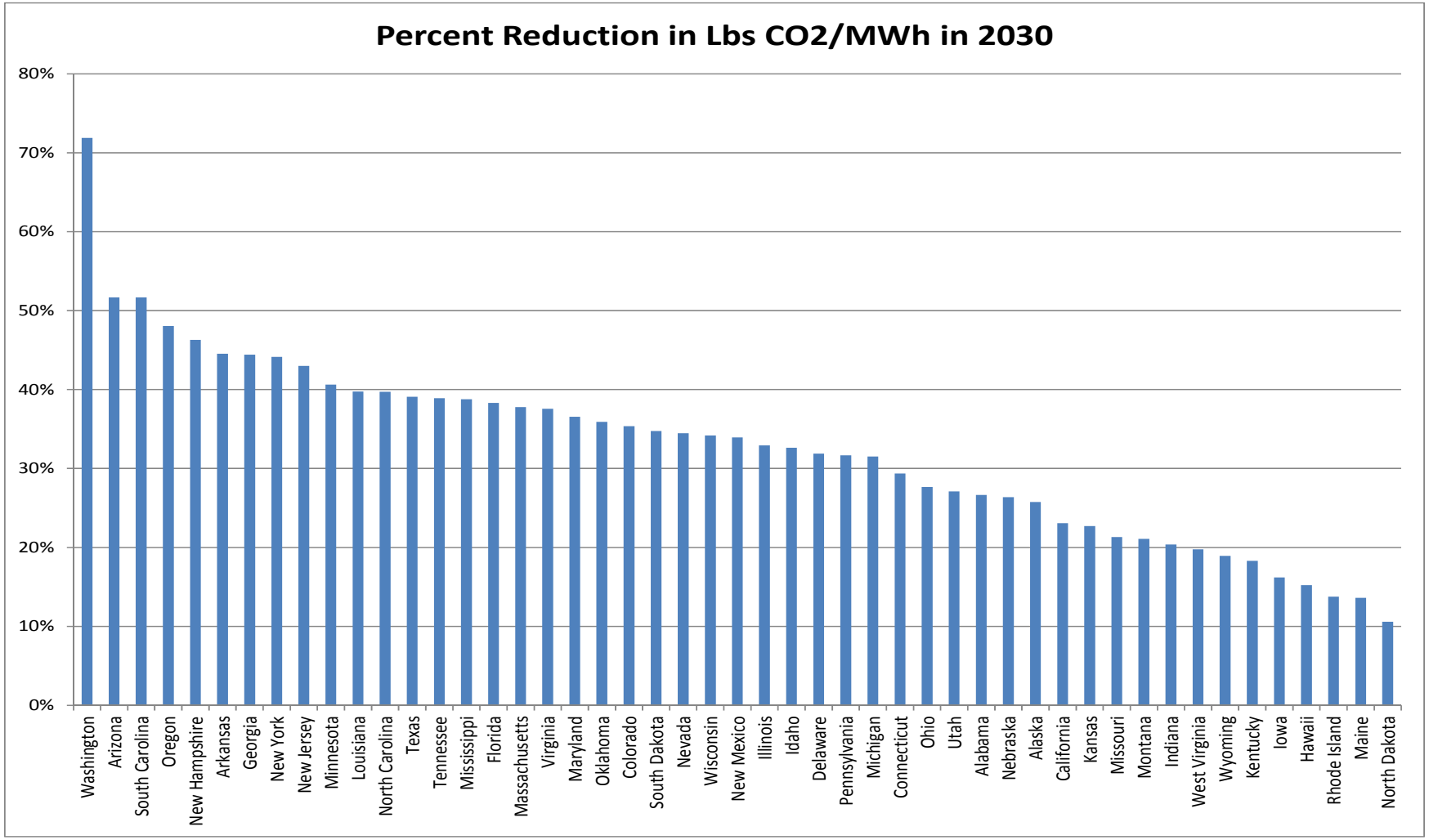

Percent Reduction in Lbs CO2/MWh in 2030
80%
70%
60%
50%
40%
30%
20%
10%
0%
Washington
Arizona
South Carolina
Oregon
New Hampshire
Arkansas
Georgia
New York
New Jersey
Minnesota
Louisiana
North Carolina
Texas
Tennessee
Mississippi
Florida
Massachusetts
Virginia
Maryland
Oklahoma
Colorado
South Dakota
Nevada
Wisconsin
New Mexico
Illinois
Idaho
Delaware
Pennsylvania
Michigan
Connecticut
Ohio
Utah
Alabama
Nebraska
Alaska
California
Kansas
Missouri
Montana
Indiana
West Virginia
Wyoming
Kentucky
Iowa
Hawaii
Rhode Island
Maine
North Dakota

EXHIBIT 5

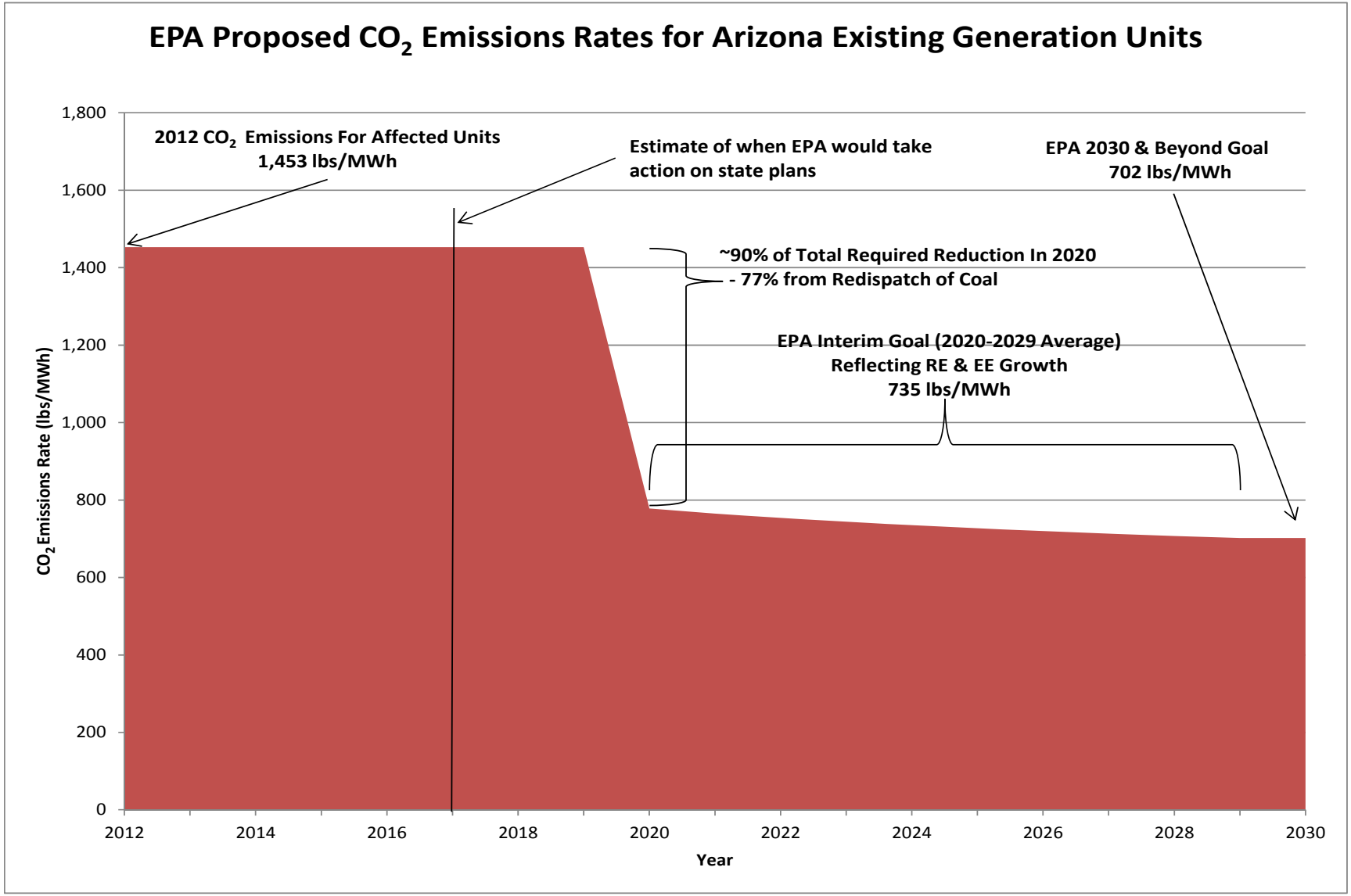

EPA Proposed CO_2 Emissions Rates for Arizona Existing Generation Units
2012 CO_2 Emissions For Affected Units
1,453 lbs/MWh
Estimate of when EPA would take action on state plans
EPA 2030 & Beyond Goal
702 lbs/MWh
~90% of Total Required Reduction In 2020
- 77% from Redispatch of Coal
EPA Interim Goal (2020-2029 Average)
Reflecting RE & EE Growth
735 lbs/MWh
CO_2 Emissions Rate (lbs/MWh)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Year

EXHIBIT 6

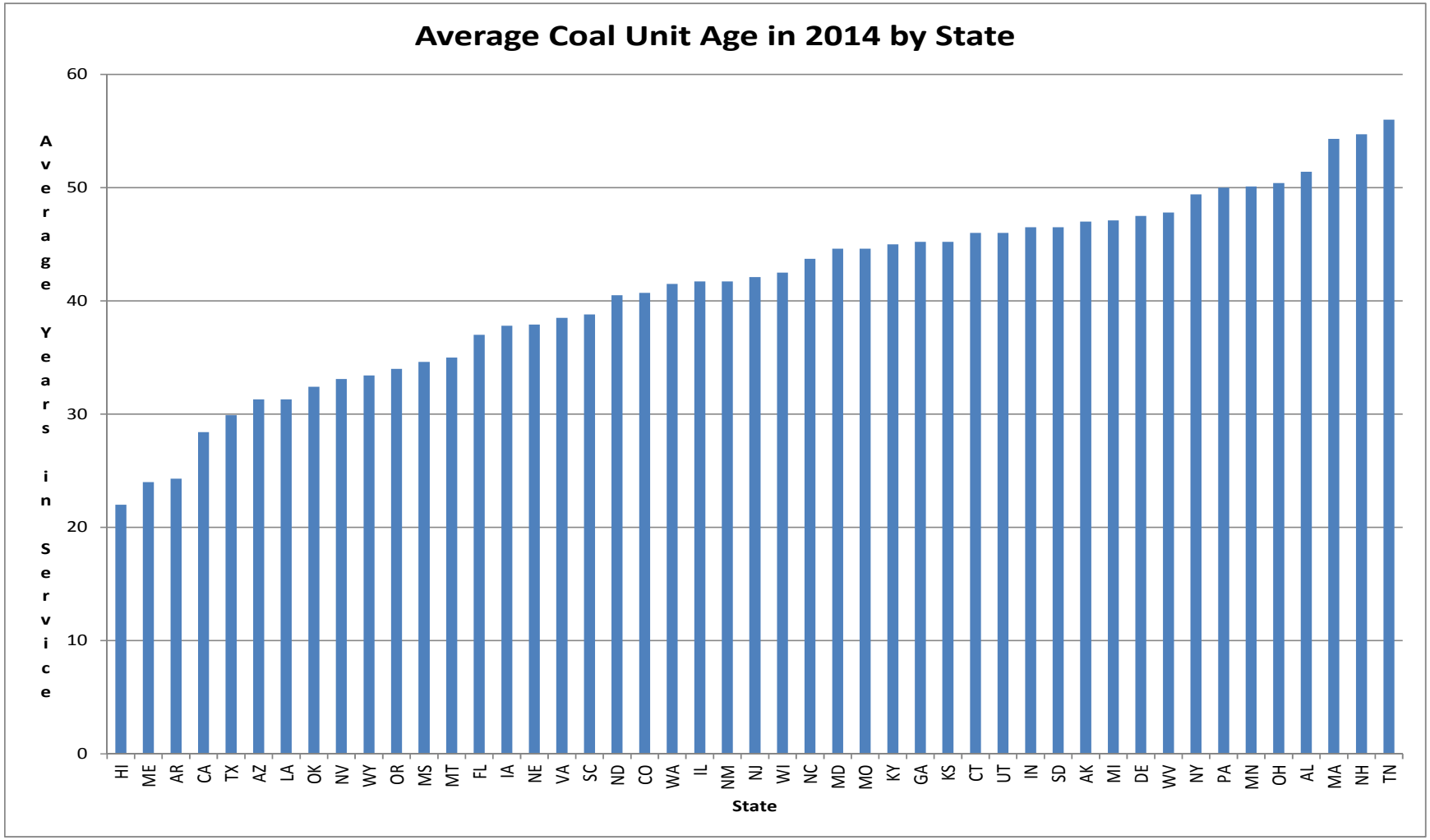

Average Coal Unit Age in 2014 by State
Average Years in Service
0
10
20
30
40
50
60
HI
ME
AR
CA
TX
AZ
LA
OK
NV
WY
OR
MS
MT
FL
IA
NE
VA
SC
ND
CO
WA
IL
NM
NJ
WI
NC
MD
MO
KY
GA
KS
CT
UT
IN
SD
AK
MI
DE
WV
NY
PA
MN
OH
AL
MA
NH
TN
State

EXHIBIT 7

Excel files, uploaded separately

EXHIBIT 8

Problems Associated with Environmental Re-dispatch in Arizona

Introduction and Background

In the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Rule), the Environmental Protection Agency (EPA) applied its newly developed best system of emission reduction (BSER) for existing fossil fuel electric generating units (EGUs) to determine carbon emission rate reductions for each state. Based on EPA's methodology, the largest carbon emission rate reduction for Arizona is based on the re-dispatch of coal-fired generation to natural gas combined-cycle (NGCC). Arizona Public Service Company (APS) analyzed the re-dispatch of coal-fired generation to NGCC in Arizona, as envisioned by the EPA, and the following provides APS' assessment of re-dispatch in Arizona.

This paper examines the base assumptions and the EPA's application of generation re-dispatch in determining Arizona's carbon emission rate reduction goals. Several real-world operational limitations overlooked by the EPA led to unrealistic policy targets that must be addressed prior to developing intensity targets. A number of these physical limitations relative to the existing electric system in Arizona are discussed in addition to the reliability requirements to serve customers in the State.

On June 18, 2014 the EPA published the proposed Rule under section 111(d) of the federal Clean Air Act (CAA) to regulate carbon dioxide emissions from existing EGUs. The Rule identifies state-specific carbon emission rate goals based on the application of the EPA proposed BSER for existing EGUs. Each state is responsible for developing a compliance plan to achieve the proposed carbon emission rate goals individually or as part of a multi-state assembly. The EPA's proposal and subsequent discussions have been clear that when developing compliance plans, the states may use either the same methodology used by the EPA to develop the state-specific carbon emission rate goals, or other methods that achieve compliance with the proposed goals.

The newly developed BSER for existing EGUs consists of four "building blocks," that include heat rate improvements at existing coal-fired plants, re-dispatch of coal generation to NGCC, and the implementation of renewable energy (RE) and demand-side energy efficiency (EE) standards. Based on the application of these building blocks, the EPA proposed state-specific interim carbon emission rate reduction goals for the 10-year period beginning in 2020 and lasting through 2029 with a final emission rate goal commencing in 2030 and continuing thereafter.

The EPA used 2012 as the baseline year for determining the carbon emission rate goals. Based on the application of the building blocks to the performance of the existing EGUs in Arizona during 2012, the EPA proposed an interim goal of 735 lb/MWh, averaged over the 2020-2029 period, and a final goal of 702 lb/MWh commencing in 2030. The final carbon goal represents a 52% reduction from the adjusted 2012 average carbon emission rate of the affected EGUs in Arizona. A preponderance of the carbon emission rate reduction is based on the re-dispatch of coal-fired generation to NGCC located within the state. In fact, the proposed EPA goals are based on 100% of the coal generation within Arizona being re-

dispatched to NGCC. The analysis below shows that using nameplate capacity along with an annualized re-dispatch assumption, rather than seasonal, monthly, or hourly data, removes resources from service that are necessary for reliability reasons.

Analysis

The method the EPA used to determine the NGCC availability for re-dispatch was based on annual capacity factor of 70%. Further, the EPA determined the annual capacity factor for NGCC located in Arizona during 2012 was 27%. Accordingly, the EPA analysis suggested that NGCC could be re-dispatched to replace all of the existing coal fired generation which would result in the NGCC annual capacity factor of approximately 53%. Therefore, the EPA determined NGCC generation re-dispatch was a viable option for setting Arizona's carbon emission rate goals and can be implemented commencing in 2020.

There are a number of challenges created by the assumptions used by the EPA in its re-dispatch analysis that are discussed in more detail below. First, the potential generation capacity of NGCC located within Arizona used the generator nameplate rating of the units rather than the net output. Net available capacity output is influenced by a number of factors, such as turbine rating, site elevation, humidity, and ambient temperatures and can differ a great deal from the nameplate rating. Generator ratings are often higher than the turbine ratings, so the unit is limited by the turbine output. Also, in Arizona, peak electrical demand occurs at the same time as peak ambient temperatures which has a net negative effect on output ratings. For example, when the temperature and electrical demand is at its highest, the units' capacity is most limited due to ambient conditions. Table 1 below shows the difference between the generation capacities of NGCC located within Arizona assumed by the EPA compared to the actual available capacities of these units. The EPA's failure to account for this situation reduces net NGCC generation capacity by nearly 2,000 MW relative to the nameplate ratings that are actually available during peak demand periods.

Table 1

	Nameplate	Summer	Winter
	MW	MW	MW
West Phoenix CC 1-3	396	255	276
West Phoenix CC 4	136	107	120
West Phoenix CC 5	570	490	506
Redhawk CC 1-2	1,140	934	1,007
Gila River CC 1	619	515	553
Gila River CC 2	619	515	553
Gila River CC 3	619	515	553

Gila River CC 4	**619**	**515**	**553**
Arlington CC	**713**	**579**	**579**
Santan CC	**1,326**	**1,227**	**1,339**
Kyrene CC	**292**	**254**	**277**
Desert Basin CC	**646**	**577**	**625**
Mesquite CC 1	**692**	**536**	**594**
Mesquite CC 2	**692**	**538**	**588**
Apache	**82**	**72**	**72**
Yuma Cogeneration Associates	**63**	**52**	**54**
Griffith Energy LLC	**654**	**570**	**570**
Harquahala CC 1-3	**1,325**	**1,054**	**1,128**
Total	**11,202**	**9,305**	**9,947**
Seasonal Net Rating Change	**-**	**1,897**	**1,255**

Source: EIA

Second, the EPA assumes the use of an annual capacity factor to determine the margin of additional energy output that can be generated by NGCC in Arizona. In doing this, the EPA must have assumed the annual capacity factor for NGCC in Arizona is a rather flat line (i.e. units are operated at a consistent level over all seasons), when in reality there is a significant difference between the electrical demands in the summer and non-summer months. For most years, the average summer demand is more than twice the average demand for the remainder of the year.

In Arizona, the most critical period for utilization of generation capacity is the period from June through September. For illustration purposes, the 16th hour of August 7th was used to show that the dispatch of all Arizona coal and gas steam units as envisioned by the EPA is physically not possible. Using data from EPA's Clean Air Markets Division[1], APS plotted the historical output from the NGCCs located in Arizona.

[1] EPA provides gross hourly generation for generators 25 MW and larger. For this analysis these values were converted to net generation using the following net generation to gross generation ratios: Coal - 0.90, NGCC 0.97, Gas Steam 0.91.

Figure 1 below shows that on August 7th, hour 16, 2012, Arizona NGCCs were generating 8,455 MW (net) and the coal and gas steam units were generating 4,098 MW (net). In order to re-dispatch all coal and gas steam with NGCC generation as assumed by the EPA, the NGCCs would have to be operating at 12,553 MW (8,455 MW + 4,098 MW). The maximum capacity assuming all units are fully available, however, is only 9,305 MW, a difference of 3,248 MW. Thus, only 850 MW of the 4,098MW of required capacity is available for re-dispatched in this hour, leaving 3,248 MW of demand that would still need to be met. This suggests that when calculating Arizona's emission goal, portions of coal and gas steam cannot be re-dispatched to NGCC and must be factored into the carbon rate goal.

Figure 1

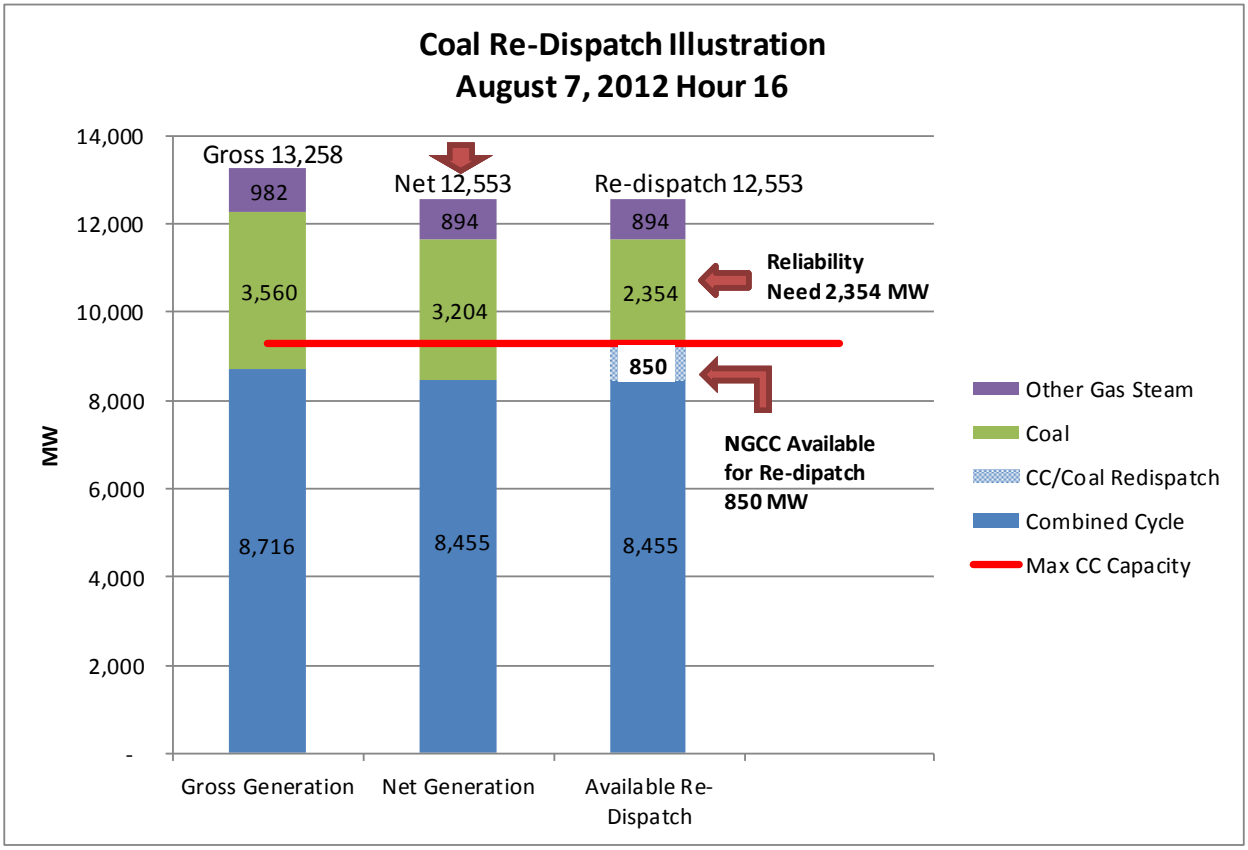
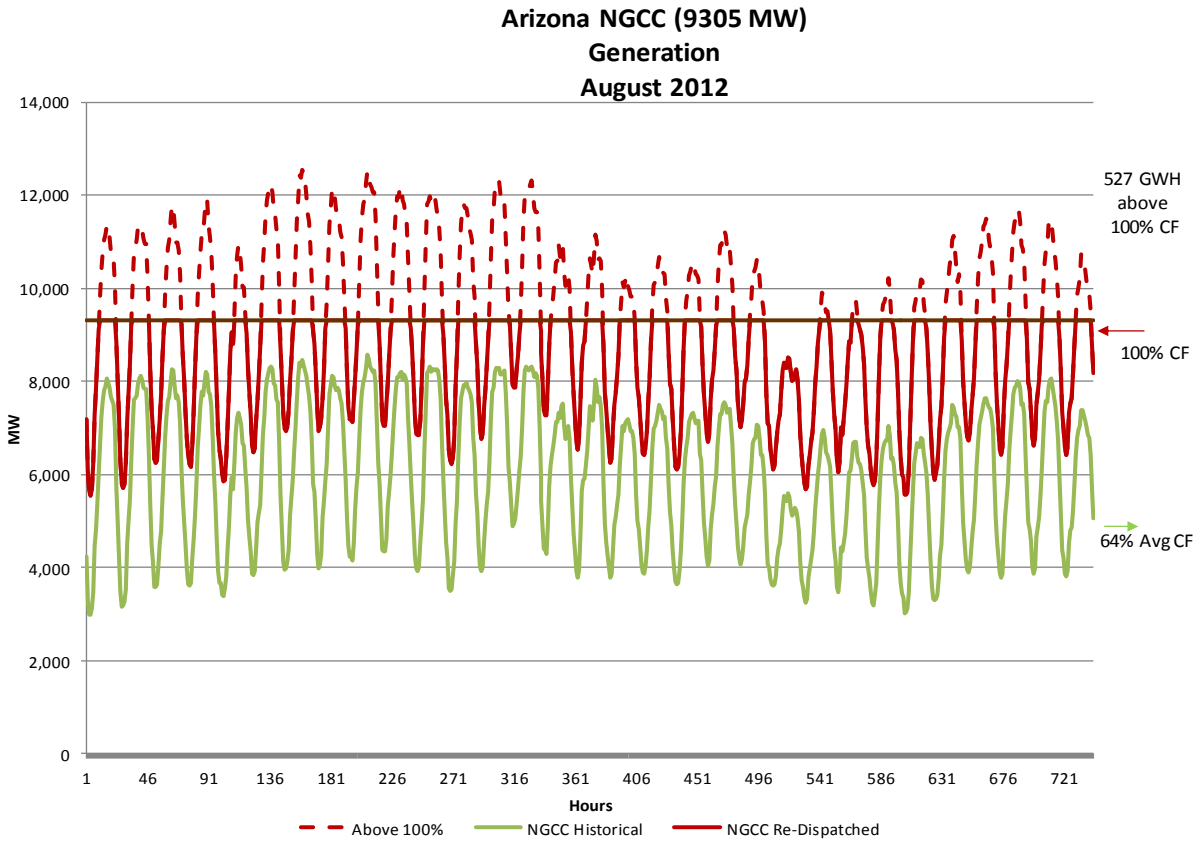


Figure 2 shows the results of this analysis for the month of August (744 hours). Actual hourly generation values for the Arizona NGCCs are indicated by the green line. Additional generation that would be required by NGCCs due to the re-dispatch of coal and natural gas steam-fired generation during the same period was added to the NGCC generation to replicate the re-dispatch as proposed by the EPA. These values are indicated by the red line. The figure also shows the maximum possible generation of the NGCCs during the summer months (100% capacity factor). As indicated by the dashed red line, nearly half of the time during August 2012 the demand that would normally be provided by coal and gas steam-fired generation exceeds the capacity of all NGCC in Arizona. This means that additional capacity is required to serve load beyond the existing NGCCs. August contains the largest number of occurrences when re-dispatch would require additional capacity; however, the same phenomenon occurs during the months of May through October. As a result, if all coal units were retired as modeled by the EPA, Arizona could face serious reliability issues in a significant number of hours throughout the year.

Figure 2



The same analysis was performed for all hours of 2012 and is summarized in Table 2. Table 2 shows that nearly 800 hours throughout the year could not meet the NGCC re-dispatch requirement envisioned by the EPA.

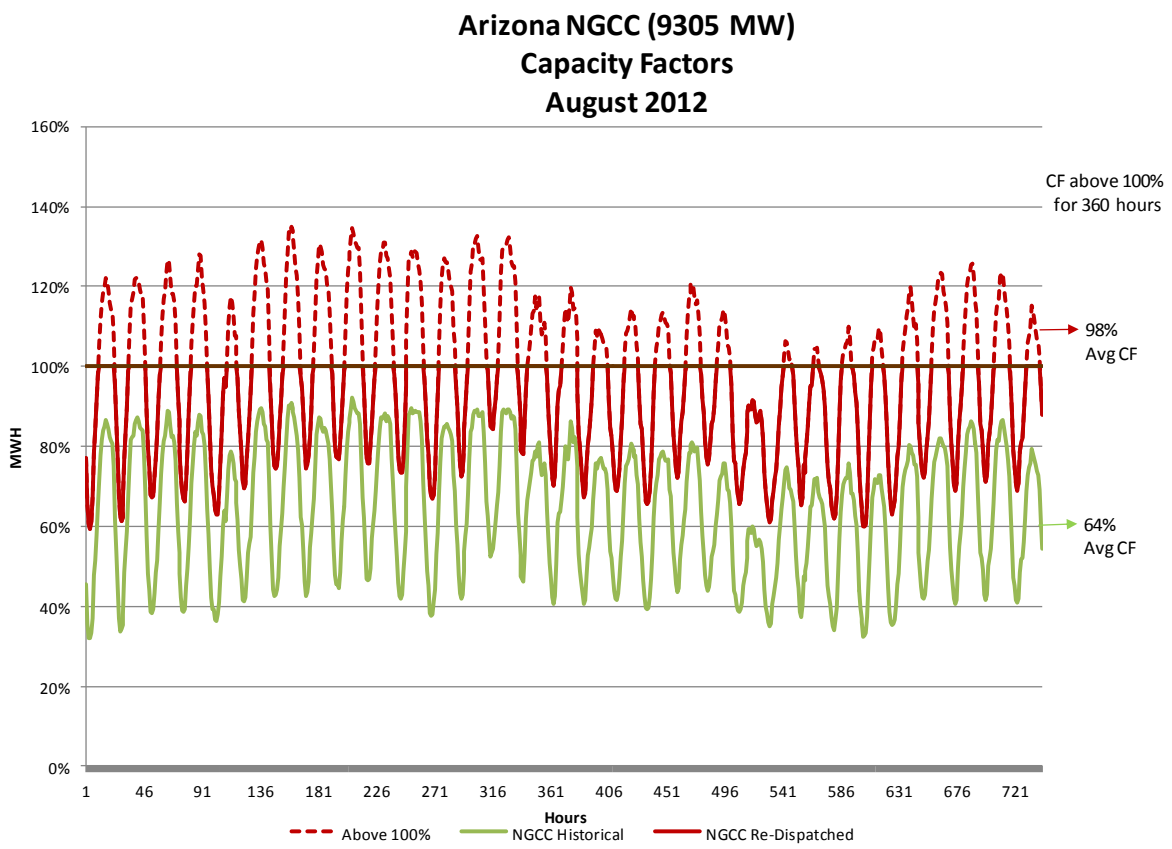
Table 2

Excess Demand

Month	GWH	Hours
January	0	0
February	0	0
March	0	0
April	0	0
May	3,147	6
June	138,369	145
July	212,637	235
August	526,832	361
September	51,529	92
October	20,313	22
November	0	0
December	0	0

Figure 3 provides a similar illustration. The green line in Figure 3 represents the actual capacity factor during the month of August 2012 for NGCC located in Arizona. The red line shows the increase in the capacity factor of NGCC with the re-dispatch of the state's coal generation. The re-dispatch capacity factor shows over 360 hours during the month where the demanded generation exceeded the available generation. During this period, the average capacity factor for all NGCC in Arizona would have to increase from 64% to 98%, which far exceeds the 70% cap proposed by the EPA. Because of the substantial increase in electrical demand in Arizona during peak times, the annual average capacity factor of NGCC cannot be used as a basis for determining the additional capacity NGCC can supply during peak demand periods.

Figure 3



Additional Concerns with EPA Plan

This analysis does not include a myriad of other considerations that must be made by the utilities that have the ultimate responsibility for ensuring that a reliable supply of energy is available to meet customer demands. For example, utilities must maintain a generation capacity reserve margin in order to supply energy in the event existing operating capacity is lost. The policy target envisioned will negatively impact existing capacity and potentially require new dispatchable units to maintain reliability and reserve margin targets.

Also, NGCCs are complex mechanical systems that malfunction even under the best of readiness and preventive maintenance programs. It is naïve and unrealistic to assume there will not be forced outages due to mechanical issues with NGCC from time to time. The EPA must consider both unit availability and the increased potential for outage with additional wear and tear on the existing fleet of NGCCs prior to developing policy targets.

There are other serious technical issues associated with the re-dispatch of coal-fired generation to NGCC. For example, the existing electrical transmission system in Arizona is designed to balance the flow of energy within the state. Because in Arizona coal-fired generation is predominantly in the eastern part of the state and the NGCC fleet is located in the western part of the state, the total re-dispatch of all coal-fired generation to NGCC will create an imbalance in the state's electrical transmission system. This imbalance can cause overloading of transmission lines, overheating of the lines, and failure of the transmission system. Without the coal plants in service, maximum load serving capability (MLSC) of the Phoenix load pocket would be significantly reduced, seriously compromising the reliability of meeting Phoenix area loads. This loss in MLSC could potentially be restored by implementing several transmission upgrade projects. These projects would come at a cost of hundreds of millions of dollars, and may not be able to be completed by 2020, the date at which the EPA assumes re-dispatch of all of Arizona's coal units.

Additionally, the natural gas capacity in Arizona to supply the re-dispatch is also questionable. Arizona has limited natural gas capacity and some of the existing capacity is now being supplied to Mexico. These issues are currently being studied by the state's utilities to determine the specific impacts and potential resolutions. While it is not known at this time what the specific resolutions may be, it most likely will involve adding new generation, transmission, natural gas capacity, or a combination thereof. All of these potential solutions are costly, take many years to implement, and are not consistent with the statutory intent behind BSER.

As stated above, APS understands that the EPA has not mandated the total re-dispatch of coal-fired generation to NGCC. APS has heard EPA's comments regarding the "flexibility" provided to the states in developing compliance plans. However, it is impossible to see how Arizona could meet the proposed carbon goals without re-dispatching virtually all coal-fired generation to NGCC, which was EPA's assumption when it calculated the state's "goals." Accordingly, any so-called flexibility touted by the EPA rings hollow.

The EPA has stated that Arizona may use other means of achieving the state goals in lieu of the re-dispatch of coal-fired generation to NGCC. For example the state may employ more renewable energy (RE) and energy efficiency (EE) requirements, EPA explains. However, Arizona analyzed increasing RE and EE standards to allow for the continued operation of a portion of the coal-fired fleet in Arizona and, in fact, these actions would have the opposite effect. By increasing the RE and EE requirements to allow for the continued operation of some coal-fired generation in meeting the final goal, the state actually moves further away from achieving compliance with the state's interim goal proposed by the EPA. On the other hand, if Arizona designs its program to comply with the interim goal, the end result is a rate that is far lower than necessary to comply with the final goal, and a far smaller portion of the state's existing coal-fired fleet is preserved.

The EPA has also suggested that the state's utilities could just operate coal-fired generation during peak demand periods, but this is not a viable option. The coal-fired power plants in Arizona are large, complex units. Typically, such units are not designed and engineered to sit idle for extended periods of time and cycle. Such practices would challenge reliable operation of the units. Moreover, the staffing and maintenance to support such a scenario would not be economically justifiable.

Ramifications of EPA's Proposal

Arizona will face a difficult dilemma as a result of the flawed assumptions used by the EPA when it evaluated the re-dispatch of coal-fired generation to NGCC. The most likely outcome of the proposed policy is that the state's utilities will be left with the difficult decision of whether to jeopardize electric reliability in Arizona, risk noncompliance with the proposed carbon reduction goals, or spend exorbitant amounts of money to offset flawed assumptions.

Electric utility companies have a responsibility to reliably supply the energy demanded by customers. In Arizona this responsibility is most critical during peak energy demand periods. Such times are generally associated with elevated temperatures, and ensuring a reliable supply of energy during such period is an important human health issue. To assure utilities can meet this responsibility, they must have reliable sources of energy generation and a reliable electric grid.

Conclusion

Complying with Arizona's carbon emission rate goals proposed by the EPA will significantly challenge the reliability of the electrical system or will lead to noncompliance with the proposed goals. Since creating an unreliable electrical system in Arizona is presumably not the EPA's intention or desired outcome, EPA must develop a workable solution for Arizona including a sensible final carbon rate target for the state.

Another method to provide some relief is the elimination of interim goals. The only real purpose for the interim goals is to measure progress towards the final goal. Because the states must submit periodic reports to the EPA, the Agency will have this information and can press the states if reasonable progress

is not being achieved. At the very least, the state should be allowed to set interim goals that provide a logical compliance trajectory for the state.

The currently proposed interim goals for Arizona are too heavily weighted toward the early years and cannot be achieved through the re-dispatch of all coal generation in the state to NGCC. Though a specific resolution is not known at this time, Arizona would have to add new generation, transmission, natural gas capacity or combination thereof, which could not be achieved by 2020, the date at which the EPA assumes re-dispatch of all of Arizona's coal units. Arizona's utilities need a more reasonable trajectory that provides additional time to fully understand the implications of the proposed rule and to assist the state to develop and implement an appropriate plan.

EXHIBIT 9

NEED FOR ADDITIONAL MAINLINE PIPELINE CAPACITY

Arizona's natural gas needs are met via deliveries on the Kinder Morgan's El Paso Natural Gas ("El Paso") and Transwestern Pipeline ("Transwestern") interstate pipeline systems delivering natural gas from the San Juan supply basin in New Mexico and the Permian supply basin in west Texas. El Paso's system is reticulated, but primarily consists of a northern system of mainline pipes that comes across northern Arizona and a set of southern mainline pipes that runs through southern Arizona, with several pipes connecting the northern and southern systems. Transwestern has a mainline system that runs across northern Arizona, with the recently constructed Phoenix Expansion line coming down into central Arizona. As discussed below in detail, there is little or no available pipeline capacity on the El Paso and Transwestern pipeline systems in Arizona to meet a sudden and large growth in natural gas requirements, with the likelihood of additional regional demand as exports to Mexico through southern Arizona continue to grow.

El Paso and Transwestern post information on available pipeline capacity on their bulletin boards. For El Paso, information at the Cornudas West point on the southern line is indicative of available south system capacity and information on the Valve City to Topock segment is indicative of available north system capacity. Data taken from the pipelines' bulletin boards in late August 2014 indicates as of August 2014, there was no unsubscribed pipeline capacity on the southern system and that El Paso's southern system pipeline capacity is fully subscribed, with El Paso's northern system having a small amount of unsubscribed pipeline capacity (approximately 195 million cubic feet/day (MMCF/day)). The lack of pipeline capacity available on El Paso's southern system is particularly telling, given that this is where most Arizona gas-fired generation is located.

Similarly, on the Transwestern northern system the Thoreau West point is indicative of mainline capacity available across northern Arizona. For August 2014, Transwestern's bulletin board indicated there was no unsubscribed capacity at the Thoreau West point. On Transwestern's Phoenix Expansion lateral (which is fed off of Transwestern's northern system) there was a limited amount of pipeline capacity available at East of Gila River Point Group (approximately 134,000 dekatherms) and the Phoenix Point Group locations (91,000 dekatherms).

In summary, there is no available pipeline capacity on El Paso's southern system or Transwestern's northern system, and very limited pipeline capacity available on El Paso's northern system and Transwestern's Phoenix Expansion line. While pipeline capacity availability varies from month to month and year to year, there is no reason to believe significant pipeline capacity on existing pipeline systems service Arizona will materialize in the near term future.

El Paso's system has two crossover pipes in Arizona where natural gas can be moved from the northern system to the southern system or from the southern system to the northern system. These is the Maricopa Lateral (coming down to Phoenix in central Arizona) and the Havasu Crossover (coming south from near the California border in western Arizona). However, capacity

on both of these lines is in demand and as of August 2014, there was no capacity available on the Maricopa Lateral and only approximately 139,000 dekatherms available on the Havasu Crossover.

A further factor putting additional pressure on pipeline capacity availability is the growing exports of natural gas off of El Paso's southern system to Mexico, via a number of current and pending pipelines. Existing Mexican exports leave Arizona via the Wilcox Lateral as well as pipes at Nogales, Arizona and Douglas, Arizona. El Paso's new Sierrita pipeline is expected to go into service in September 2014 and will provide additional export capacity to Mexico near Sasabe, Arizona. The Sierrita pipeline is being constructed in a manner that allows for significant expansion of it in the future. Additional exports to Mexico are likely in the future as demand in Mexico continues to outstrip local production. For example, the Energy Information Administration noted that "U.S. natural gas exports to Mexico grew by 24% to 1.69 billion cubic feet per day (Bcf/d) in 2012, the highest level since the data collection began in 1973" and that "Natural gas consumption is rising faster in Mexico than natural gas production, and as a result, Mexico is relying more on natural gas imports from the United States."[i]

As shown on the map below, most Arizona natural gas-fired generation is located along El Paso's southern system, with a handful of plants also having access to Transwestern's Phoenix Expansion pipeline. This corresponds with the increase in demand for electricity in the fast-growing Phoenix and Tucson metro areas in recent decades.

Source: Energy Information Administration

The lack of existing pipeline capacity, in combination with growing Mexican demand via southern Arizona, indicates that if significant additional natural gas supplies need to enter central and/or southern Arizona to meet gas-generation demand increases caused by the closure of coal plants, the construction of significant new mainline pipeline facilities will be required. The construction of such new facilities involves significant planning, cost, and time.

The recent construction of Transwestern's Phoenix Expansion pipeline is a good example of a major pipeline project in the desert southwest. This project involved some upgrades to Transwestern's system coming out of the San Juan production basin in northwest New Mexico, the use of then available mainline capacity across northern New Mexico and Arizona, and construction of a new pipeline from near Ash Fork, Arizona south to the west side of the Phoenix metro area and then south and east to near Coolidge, Arizona. The San Juan upgrade involved 25 miles of 36 inch pipe, adding 375,000 MMcf/day of additional capacity from the Blanco point to the Thoreau point. The Phoenix Expansion part of the project involved 259 miles of pipe (95 miles of 42 inch pipe and 164 miles of 36 inch pipe) with a capacity of 500,000 MMcf/day. This project was constructed to provide additional pipeline capacity into central Arizona and the vast majority of its service is to electric generating units. The table below shows the actual timeline from the initial non-binding

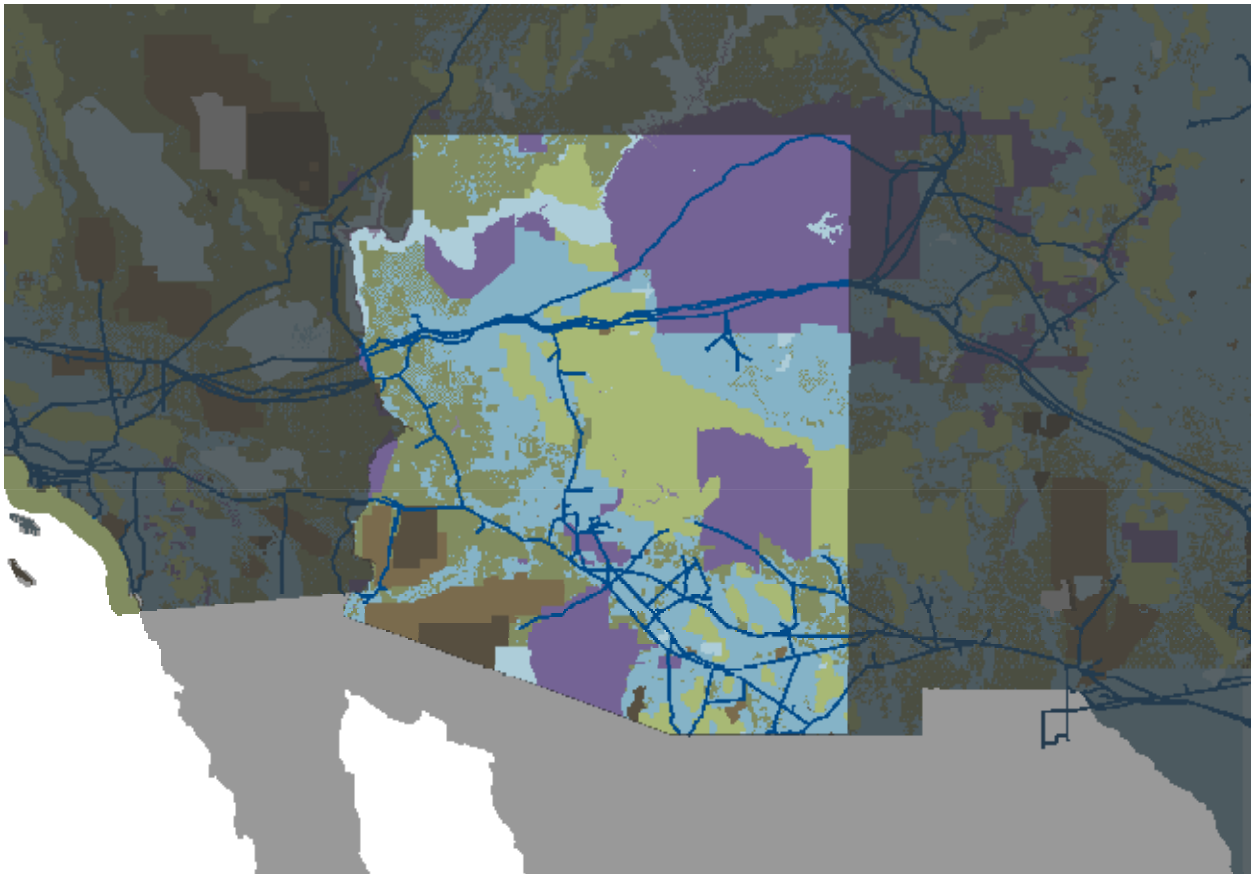
open season to its in-service date. It should be noted that there were on-going discussions and planning prior to the non-binding open season.

Transwestern Phoenix Expansion Timeline	
May 11, 2004	Non-binding open season begins
December 1, 2004	Binding open season begins
November 10, 2005	Transwestern files request with FERC for initiation of pre-filing process for Phoenix Expansion Project (FERC Docket PF-06-4)
December 16, 2005	Arizona Public Service Company pre-approval filing with the ACC
February 22, 2006	Southwest Gas Corporation pre-approval filing with the ACC
March 23, 2006	ACC Decision on Arizona Public Service Company pre-approval filing (Decision No. 68597)
June 5, 2006	ACC Decision on Southwest Gas Corporation pre-approval filing (Decision No. 68753)
September 15, 2006	Transwestern makes certificate filing with FERC (FERC Docket CP06-459) – (the filing projected some facilities would be in service May 2008 and all facilities would be in service by October 2008)
September 29, 2006	UNS Gas Inc. pre-approval filing with the ACC
February 22, 2007	ACC Decision on UNS Gas, Inc. pre-approval filing (Decision No. 69333)
November 15, 2007	FERC issues an order authorizing construction of the Phoenix Expansion Project
March 1, 2009	Transwestern's Phoenix Expansion Project in-service date

Thus, from the time of the initial non-binding open season to the in-service date was close to five years. Additional issues of note regarding Transwestern's Phoenix Expansion Project include:

1. Construction of major pipeline projects is very expensive, with the total cost of the Transwestern Phoenix Expansion costing roughly $958 million. This is significantly more expensive than the initial projected cost of approximately $660 million. Transwestern has cited a number of contributing factors to the higher overall cost, including higher costs for right-of-ways and permits, material costs, construction costs, and environmental inspection costs. Constructing new pipeline capacity to meet significant new natural gas demand in Arizona would entail the addition of pipeline capacity from either the San Juan Basin in New Mexico or the Permian Basin in west Texas, a considerably longer distance than the Phoenix Expansion Projects represents. The cost to build such pipeline capacity has undoubtedly increased in the intervening years since the shorter Phoenix Expansion was built for $958 million.

2. Land in Arizona is owned by a wide variety of entities, including various tribal, federal, state and private landowners. Private land represents only 17.6 percent of Arizona's land area. Working with a large variety of different landowner interests can be a significant complication in developing a lengthy pipeline project. The map below provides some perspective on the land ownership in relation to the location of interstate pipelines in Arizona. There are likely some circumstances where development and other factors simply preclude the expansion of existing pipeline facilities or construction of new pipeline facilities. For example, in developing the Phoenix Expansion, Transwestern indicated to the ACC Staff at the time that there was development encroaching on right of way options in the Prescott, Arizona area and that if a pipeline project such as the Phoenix Expansion were not sited soon in the area, use of the possible routes through the Prescott area would soon be precluded from use due to further development in the area.



Source: Energy Information Administration

3. Many parts of Arizona are mountainous and remote, presenting difficult construction conditions.

4. Land acquisition in Arizona is difficult, with no "quick take" provisions, meaning that land acquisitions had to occur without court involvement and involve significant negotiations with various land owners.

5. The actual time to construct a new pipeline is hard to know, as various factors can extend the timeframe beyond what is expected. For the Phoenix Expansion, the in-service date ended up being significantly later than was projected at the beginning of the process.

OPERATIONAL FLEXIBILITY

Another significant issue related to natural gas supply is the need for operational flexibility to provide utilities the ability to turn cycle their power plants on and off as needed. Natural gas is the most flexible conventional generation technology and thus is relied on heavily to respond to fluctuating electricity demand, a feature that is becoming ever more important in the Desert Southwest as renewable energy generation grows. When a power plant is not operating, it consumes little or no natural gas. When it begins operating, it suddenly places a significant demand for natural

gas on the interstate pipeline. These swings from no demand to significant demand and back and forth can place significant pressure on the interstate pipeline system to accommodate such needs. Arizona has no market area natural gas storage and thus heavily reliant on interstate pipeline line pack to meet the fluctuating demand for natural gas.

NATURAL GAS STORAGE

Natural gas storage has been a point of discussion in Arizona for many years and interest has grown as the state has become much more dependent on natural gas for generating electricity. As the Energy and Environmental Analysis Inc.'s 2006 study entitled Arizona Natural Gas Market and Infrastructure Study notes:

"Since Arizona currently lacks storage capacity within the state, any storage capacity would be extremely valuable to meet daily and hourly swings of growing gas use in power generation."

Arizona's geology is such that the reservoir and depleted field storage facilities that have been constructed in other parts of the country would not be an option in Arizona. Arizona does have a number of large salt deposits that could host a natural gas storage facility. However, some sites are not considered viable, given encroaching development and other considerations. The number of known possible sites is very small (possibly as small as one) and there are a variety of issues to be resolved before salt cavern natural gas storage could be built in Arizona, including cost, time to construct, land availability and acquisition, and brine disposal.

The area that has been the focus of discussion in recent years is the Picacho Basin area between Phoenix and Tucson. In a 2011 presentation to the ACC, El Paso indicated that a possible project in the area, with 2,000,000 to 4,000,000 dekatherms of working capacity and 400,000 dekatherms of deliverability per day would cost approximately $320 million as of 2008. This project had a projected timeline of over four years to the first cavern being available and over eight years to the fourth and final cavern being available. The significant uncertainties regarding development of natural gas storage in Arizona make it likely that cost and time estimates would increase and it is not a certainty that a natural gas storage facility will be able to be built. However, absent such a project, Arizona would become ever more dependent on interstate pipeline line pack to handle the variations in natural gas demand for power generation. Development of new natural gas infrastructure, whether pipelines or gas storage facilities, is a long process, a necessity given the need to develop projects that integrate into the existing system, meet customer needs, address potential environmental issues, and address any other public interest concerns that may be raised. Rushing the process to construct such projects to meet an arbitrary interim goal is likely infeasible and is certainly inadvisable.

GAS-ELECTRIC COORDINATION

Greater coordination between the natural gas and electric industries has been a topic of growing interest in recent years for a number of reasons, including the growing presence of renewable energy

resources across the nation and growing reliance on natural gas generation. Both of these are significant factors in the Desert Southwest. The Federal Energy Regulatory Commission and the North American Energy Standards Board are currently considering ways to enhance the coordination between the electric and natural gas industries. Comments to the FERC Notice of Proposed Rulemaking are due on November 28, 2014.[ii] In the Desert Southwest, including Arizona, the need for greater gas-electric coordination is important and growing each year as the region grows more dependent on natural gas and intermittent renewable energy resources. Arizona entities are key participants in the Desert Southwest Pipeline Stakeholders group that made a number of proposals to provide greater operational flexibility for natural gas generators who hold firm pipeline capacity rights on interstate pipelines. Arizona's interests in this proceeding are focused on providing electric generators great ability to manage their natural gas supplies during peak afternoon/early even periods during the summer. At this point it is unclear to what extent Arizona's gas-electric coordination needs will be addressed in the current FERC/NAESB process. To the extent Arizona's interests are not meaningfully addressed in the FERC/NAESB process, a significant ramp up of Arizona's reliance on natural gas over a short time frame is cause for concern.

SCHEDULING OF SAFETY INSPECTIONS AND MAINTENANCE

A further concern with significantly greater natural gas reliance year round is its impact on the ability of pipelines to schedule necessary safety inspections and maintenance activities. Currently pipelines try to conduct most of these activities in the spring and fall seasons when natural gas demand drops off significantly. However, even in the current environment, growing natural gas demand in the last decade or so has squeezed the windows of opportunity for pipelines to undertake these necessary activities. If natural gas generation significantly replaced coal generation in Arizona, natural gas demand in the spring and fall periods would rise considerably. Initial discussions with one of the interstate pipelines serving Arizona points to the likelihood that safety inspections and maintenance activities may have to be spread out across the calendar, as natural gas demand would be relatively high in all seasons. Under such a scenario, there is a greater likelihood of the need to take some amount of pipeline capacity out of service at times of high natural gas demand, lessening the capacity available to provide service to electric generation facilities.

SHIFT FROM A DIVERSE GENERATION PORTFOLIO

Elimination of much if not all of Arizona's coal generation would drastically shift Arizona's generation mix from one which is quite diversified to one that is very heavily reliant on natural gas generation. Apart from the simple fact that diversified portfolio of generation resources is preferable, there are a number of long term implications of such a shift.

HOMELAND SECURITY CONCERNS

A primary concern in this area is the introduction of homeland security risks of relying on a handful of pipes to fuel a vast majority of Arizona's electric generation. In a number of areas some of these pipes run in close proximity to each other and could become a target for terrorist activity.

The region might be able to absorb the loss of a 30 inch mainline pipe for a period of time, as happened with the Pecos River explosion near Carlsbad, New Mexico in 2003. In that instance, one of El Paso's south system mainline pipes exploded and was thus out of service for a period of time as El Paso moved into its lower throughput spring season . In this circumstance El Paso and its shippers were able to work together to maintain service to all shippers, despite losing a noticeable amount of pipeline capacity for a period of time. Electric utilities were able to rely on other generation assets in the area, principally coal and nuclear generation, during this time when gas supplies were constrained. However, natural gas demand has grown significantly since 2003 in the desert southwest and the potential loss of multiple mainline pipes represents the very real risk of crippling electric generation in the desert southwest for a significant period of time, leading to potentially catastrophic results. A sudden shift to much greater reliance on natural gas generation greatly exacerbates this concern.

NATURAL GAS PRICE VOLATILITY

Another concern with becoming heavily dependent on natural gas for electric generation is the potential for natural gas price volatility to create much more unstable electricity rates than have been seen in the past in the United States or Arizona. By its nature, the total cost of natural gas generation is weighed more heavily toward fuel costs and less toward facility costs, thus making the cost of natural gas as a fuel extremely important. Prior to the shale gas revolution, the United States experienced years of very volatile natural gas prices, with exponential swings in natural gas prices experienced multiple times, particularly during winter heating seasons. Natural gas prices have been much less volatile since the introduction of large volumes of shale gas into the natural gas supply portfolio of the United States. However, in the future there is no guarantee that natural gas prices will not return to a state of great volatility, particularly if natural gas demand is driven much higher by heavy reliance for electric generation in the future.

OTHER ISSUES REGARDING NATURAL GAS SUPPLIES

Another matter of note is that a number of existing natural gas generation facilities in the Phoenix metro area are served off of El Paso's lateral system in the area. This lateral system has capacity constraints that at times in the past have raised concerns regarding the ability of both electric generators and local gas distribution companies to meet their full supply needs on a cold winter day. Reliance on running such Phoenix area natural gas generation facilities at a high capacity factor may run afoul of the limitations inherent in El Paso's Phoenix area lateral system. Expansion of the El Paso's Phoenix area lateral system would be very difficult and costly, and really is improbable, given the built up nature of the metro area where the existing system lines are located.

Some Arizona electric generators, including the incumbent local utilities, have sculpted capacity contracts with El Paso, the result of proceedings at FERC in the mid 2000s where issues surrounding the availability of capacity on the El Paso system were dealt with at FERC. Electric generators were allocated much greater pipeline capacity during the summer months to meet their

summer peaking needs, while natural gas distribution companies were allocated much greater winter pipeline capacity to meet their winter heating needs. These existing seasonally sculpted capacity contracts still exist and thus incumbent local utilities do not currently hold as much pipeline capacity during non-summer months. While utilities do have the ability to adjust their pipeline capacity holdings over time, the current lack of available pipeline capacity in the region would likely make it more difficult for the utilities to acquire additional non-summer pipeline capacity rights if they needed to run their electric generation assets year round. Merchant natural gas generation plants could have even more difficulty in acquiring existing pipeline capacity, given that many of them currently hold little or no firm pipeline capacity and may rely on the availability of interruptible capacity.

Natural gas service can be impaired at times by unforeseen force majeure events that can take a portion of the pipeline system out of operation in an unexpected fashion. In a recent example, El Paso's Havasu Crossover line experienced a force majeure event on August 20-22, 2014, taking the line from its normal capacity of 650,000 Mcf/day to zero due to the discovery of a line leak.

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[i] March 13, 2013 United States Energy Information Administration article entitled "U.S. natural gas exports to Mexico reach record high in 2012."

[ii] FERC Docket No. RM-14-2-000

EXHIBIT 10

LOCATION OF COAL AND NGCC GENERATION IN ARIZONA

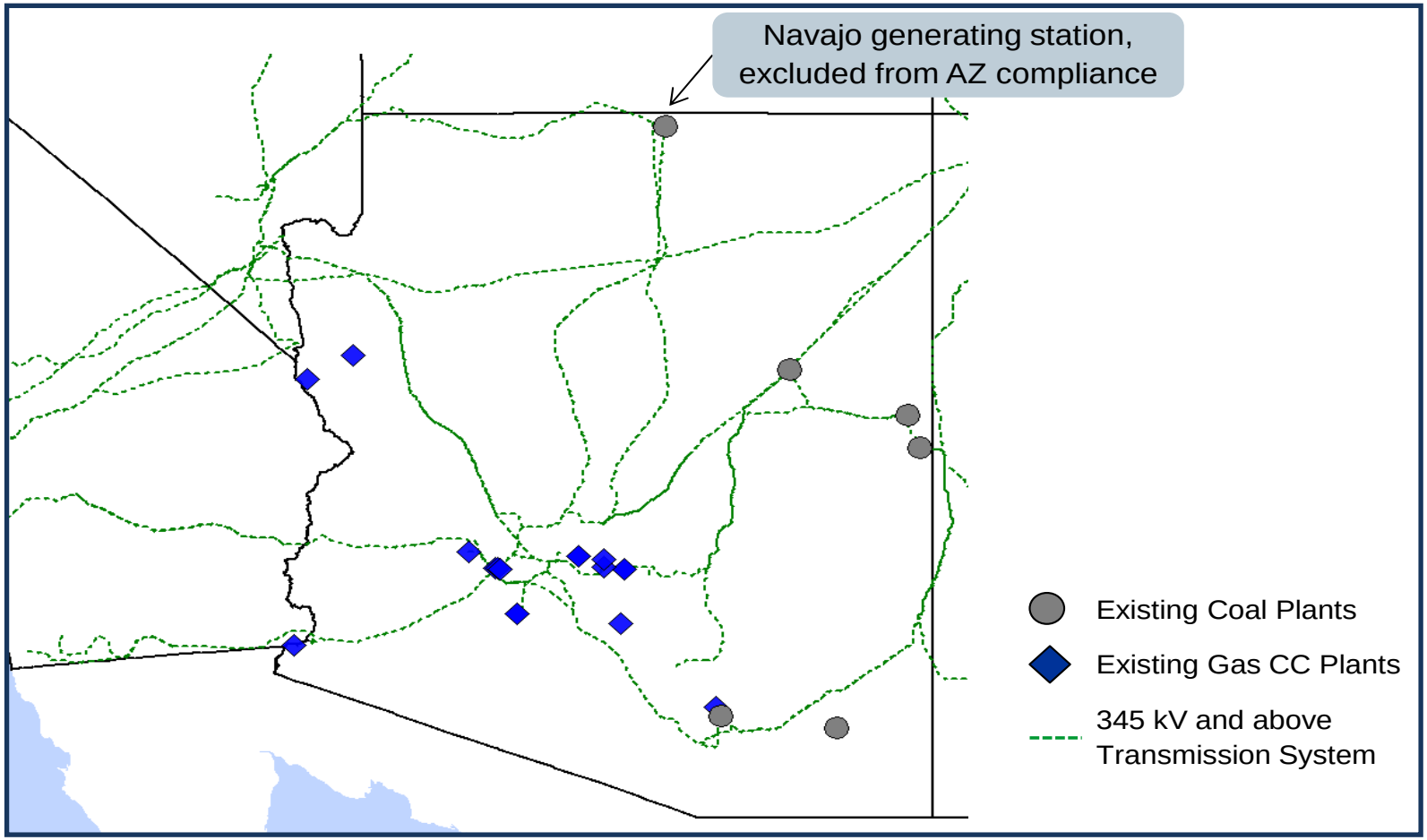


EXHIBIT 11

FOR DISCUSSION PURPOSES ONLY

Coal Plant Shutdown Assessment Report of SWAT Investigation

Presented to SWAT CRATF

July 10, 2014

Ron Belval
Transmission Planning

Sara Eftekharnejad
Transmission Planning

Outline

- SWAT Coal Plant Retirement Study Activities
- Regional Outreach
- Study Scope
- Modeling & Analysis
- Results
- Issues Requiring Further Research
- Conclusions
- Recommendations

SWAT Actions and Issues

- Agreement on need to study impact of coal plant shutdowns expected by 2019
- Key Issues;
  - Loss of “inertia” resulting in possible stability impact
  - Less than five years to respond
  - Change in generation pattern will impact Path Ratings
  - Problem goes beyond SWAT coal plant reduction
    - SONGS Retirement (~2000 MW)
    - California – Retirement of gas fired once through cooling plants (~8000 MW)
- Coal Reduction Assessment Task Force (CRATF) formed at February 19, 2014 SWAT Oversight Meeting
  - Guidance to define problem and study scope
  - Agreement on need to reach out to California and other entities

Coal Reduction Study Objectives

Phase 1:

- To identify possible reliability issues due to loss of inertia and/or dynamic reactive capability associated with anticipated coal plant shutdowns
- To identify potential limit to shutdowns through sensitivity analysis

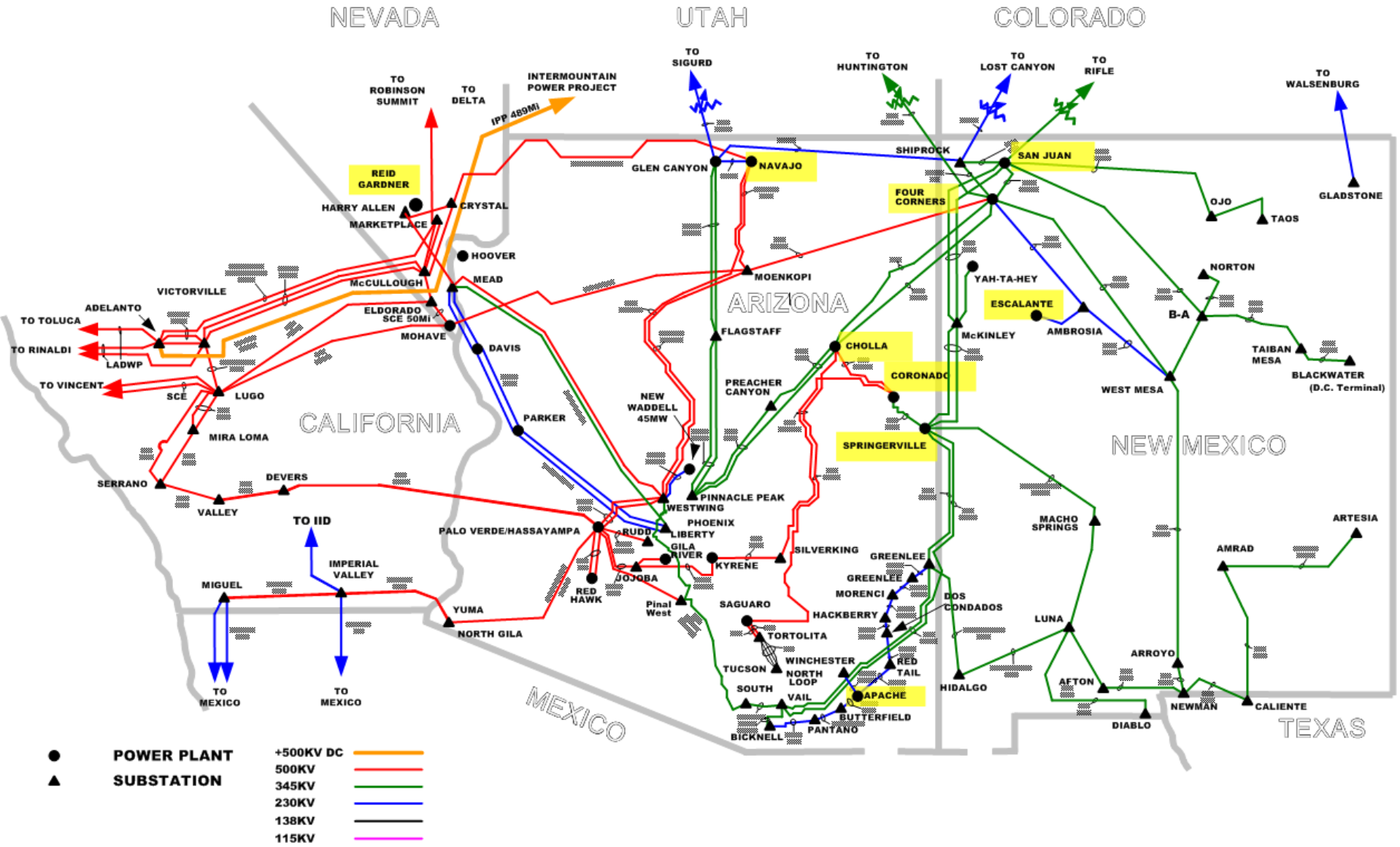
Phase 2:

- Specific objectives to be determined upon completion of Phase 1
- Possibly Identify Path Rating issues associated with change in generation resource mix and plant locations due to anticipated coal plant shutdowns

SWAT Coal Plant Retirement Discussion

- SWAT area coal reduction of approximately 25% (of ~10 GW total) by 2019
  - California plans to mitigate SONGS and once-through cooling retirements with preference resources
- Possible transmission system impacts
  - Dynamic stability issues
  - Potential Path Rating changes due to change in generation fleet
- Modeling and Analysis
  - Simulate coal reduction generation dispatch
  - Consider G-1, N-1 and some N-2 contingencies
  - Depending upon study results, consider dispatch modifications if needed to maintain dynamic stability

SWAT Coal Plants



Baseline and Scenario Assumptions

- Baseline
  - Reference case without coal plant shutdowns
- Scenarios
  - Coal plant capacity retirements expected by 2019
  - Specific units modeled out of service to accurately simulate plant shutdowns.
  - Specific generating units and locations identified to replace retired units to the extent information was available
- Sensitivities
  - Sensitivity to renewable/gas ratio for expected retirements
  - Sensitivity to renewable/gas ratio for high coal reduction

Modeling and Data Exchange

- Transient stability scenarios for dynamic studies
- List of multiple contingencies used for the power flow studies
- Update dynamic models for coal plants that will be converted to run on natural gas
- Dynamic models for new gas turbines that will be built on sites of retired coal plants and within load centers
- Models for renewable resources not included in the 2019HS case that will replace the output of the retired coal plants
  - WECC has offered to provide assistance modeling wind and solar resources.

Outreach to WestConnect

- NV Energy is interested in pursuing
- CRATF formation presented at the WestConnect Annual Planning Meeting on February 20, 2014
- CCPG has addressed the issue in its area
  - Plans to build new gas fired generation on the existing coal plant sites
- Presented Initial Study Results at the Arizona ACC BTA Workshop on May 15, 2014
  - No stability issues identified at that time
- Discussed at the WestConnect PMC on June 17, 2014:
  - Reported that coal plant reductions approaching 50% of SWAT footprint with high renewable resources/minimal new gas generation appears to impact transmission reliability
  - Interest in reporting results to EPA after results are validated

Outreach to CAISO

- Verbal contact with CAISO on February 21, 2014
  - Willing to work with us, but will await our response to bring this matter up internally or with other regions
  - CAISO representation on CRATF WebEx meetings

- CAISO Situation
  - Has had five years to address SONGS and Once-through gas generation shutdown
  - Relationship with IID, SMUD and LADWP
  - Willing to work with SWAT and/or WestConnect

Outreach to California TOs

- Participants in CRATF webinars
  - IID
  - LADWP
  - SCE
- Verbal contact with SDG&E in June, 2014
  - Reported preliminary results following CRATF TO call on June 24, 2014

Planning Regions Coordination

- Regional Planning Coordination Meeting February 28, 2014
  - One of 3 Objectives: "Identify opportunities to coordinate current transmission needs/solutions spanning more than one Planning Region"
  - Participants: CAISO, CG, NTTG & WC
- Presented to TEPPC TAS on April 29, 2014
  - WECC interested in following progress and reviewing results
  - Possible opportunities for coordination
  - Request to present at TEPPC August 13-14, 2014 meeting
- Discussed with Southwest Power Pool (SPP) on July 1, 2014
  - SPP interested in reviewing results and possibly coordinating comments

Power Flow Modeling and Analysis

- Power Flow Model and Analysis
  - Baseline: 2019 HS WECC/AZ Coordinated Case / No Coal Reduction
  - “CR Scenario” Case: Expected Coal Reduction with Planned new Gas
  - “CR Scenario Renewable” Case: Expected Coal Reduction with Planned new Gas replaced by Renewables
  - “CR Sensitivity High Renewable” Case: High Coal Reduction with High Renewables
  - “CR Sensitivity Gas/ Renewable” Case: High Coal Reduction with Renewables and Planned new Gas
- Contingency Analysis
  - Single and Category C multiple contingencies within the SWAT footprint.
  - Benchmark Scenario and Sensitivity cases against Baseline with pre-coal reduction dispatch

Transient Stability Analysis

- Disturbances:
  - 3-phase fault with normal clearing
  - 3-phase or single-line-to-ground fault with delayed clearing (breaker failure)
  - 3-phase fault with normal clearing plus loss of circuit on common tower or in common corridor.
  - Voltage, frequency and rotor angle plots are created for identified buses

Status of Technical Analysis

- Case Preparation
  - Baseline Case: No coal reduction
  - Expected Coal Reduction Scenario with Planned Gas replacement
  - Expected Coal Reduction with Renewable replacement
  - High Coal Reduction with High Renewables
  - High Coal Reduction with High Renewables and Planned Gas units
- Power Flow Analysis
  - Analysis of all TO provided contingencies completed on all cases
  - Comparison of all cases against Baseline cases completed
- Transient Analysis
  - Simulations of all TO provided transient scenarios completed
  - Comparison of Baseline & CR Scenario/Sensitivity results completed

Modeled Power Flow Coal Generation Dispatch (MW)

Coal Units	Baseline No CR	"Gas " & "Renewable" CR 2k	"High Renewable" CR 5k Sensitivity	"High Renewable\Gas" CR 5k Sensitivity
Four Corners 1 - 3	0	0	0	0
Four Corners 4 & 5	1597	1597	748	748
San Juan 1	360	360	0	0
San Juan 2 & 3	894	350	0	0
San Juan 4 (PNM Swing Generator)	472	415	505	527
Navajo 1	805	0	0	0
Navajo 2 & 3	1610	1610	805	805
Apache 2& 3	389	389	195	195
Cholla 1 - 4	1119	1119	1119	1119
Coronado 1 & 2	850	850	429	429
Springerville 1 - 4	1650	1441	1391	1391
Reid Gardner 1-3	0	0	0	0
Reid Gardner 4	257	0	0	0
Total	10003	8131	5192	5214
Reduction from Baseline		1872	4811	4789

Power Flow Modeled Gas Generation (MW)

Coal Units	Baseline No Reduction	CR 2k "Gas"	CR 2k "Renewable"	"High Renewable" CR 5k Sensitivity	"High Renewable\Gas" CR 5k Sensitivity
Reid Gardner CC Unit 1	0	180	0	0	180
Reid Gardner CC Unit 2	0	180	0	0	180
Reid Gardner CC Unit 3	0	230	0	0	230
Ocotillo	0	95	0	0	95
Ocotillo	0	95	0	0	95
Ocotillo	0	95	0	0	95
Ocotillo	0	55	0	0	55
Ocotillo	0	55	0	0	55
San Juan GT	0	170	0	0	170
La Luz GT	0	40	0	0	40
Total Planned Gas Units	0	1195	0	0	1195

Power Flow Modeled Incremental Renewable Power Output (MW)

New PV Units	Baseline No CR	"Gas " CR 2k	"Renewable" CR 2k	"Renewable" CR 5k	"High Renewable\Gas" CR 5k Sensitivity
Rooftop PV in Arizona	0*	0	0	1360	950
Utility scale PV in Arizona	0	0	514	804	804
Rooftop PV in New Mexico	0	0	0	300	85
Wind unit in New Mexico (San Juan)	0	0	210	450	450
Utility scale PV in Nevada	0	300	890	890	300
Utility scale PV in TEP	0	60	60	112.3	112.3

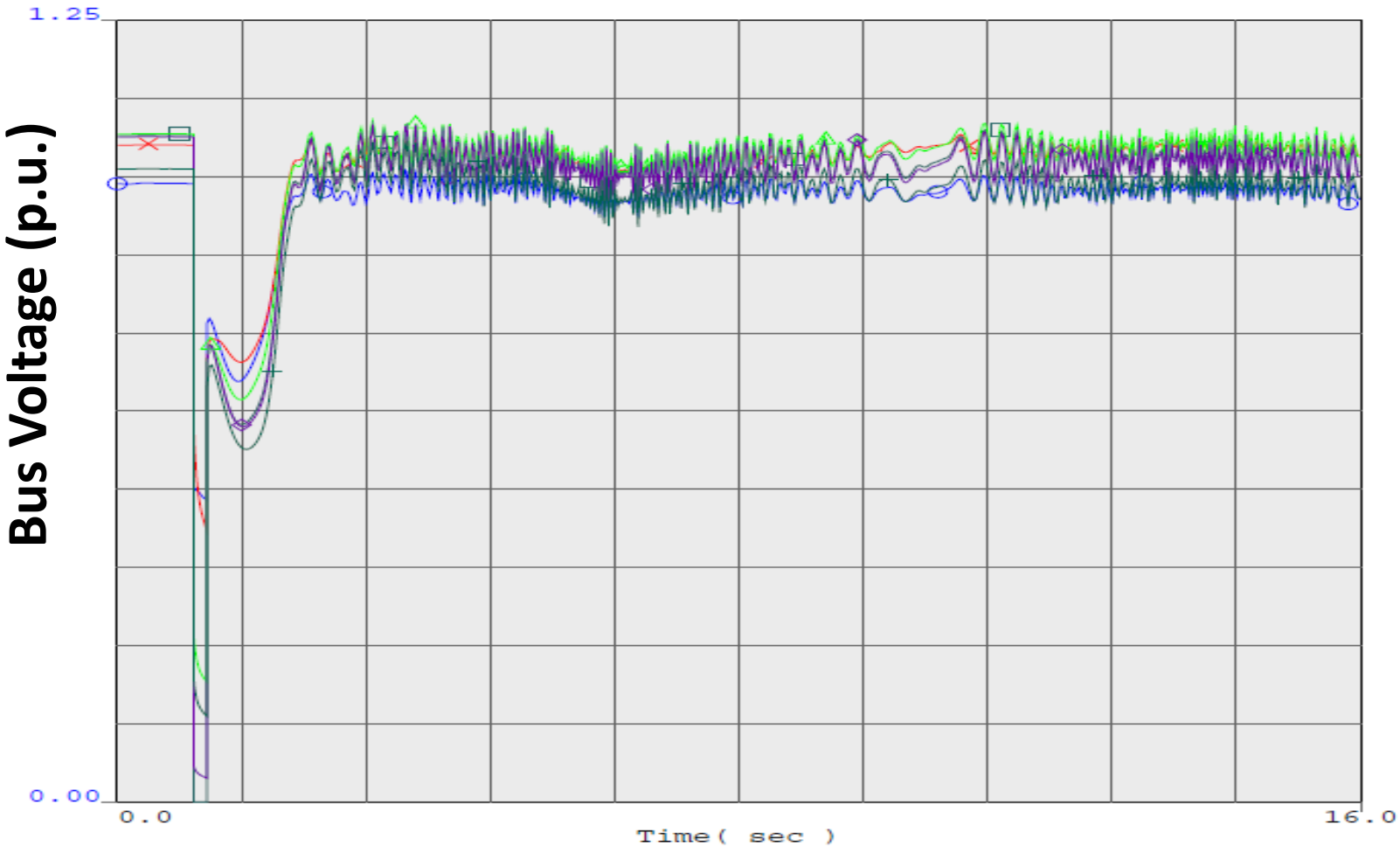
* Indicates amount of renewable resources in addition to that which was already in service in the 2019 case.

Baseline Scenario

- 2019 Arizona Coordinated Heavy Summer Base Case
- No Coal Plant Retirements Assumed

Baseline

Fault at Largest Single Generating Unit, Loss of Unit

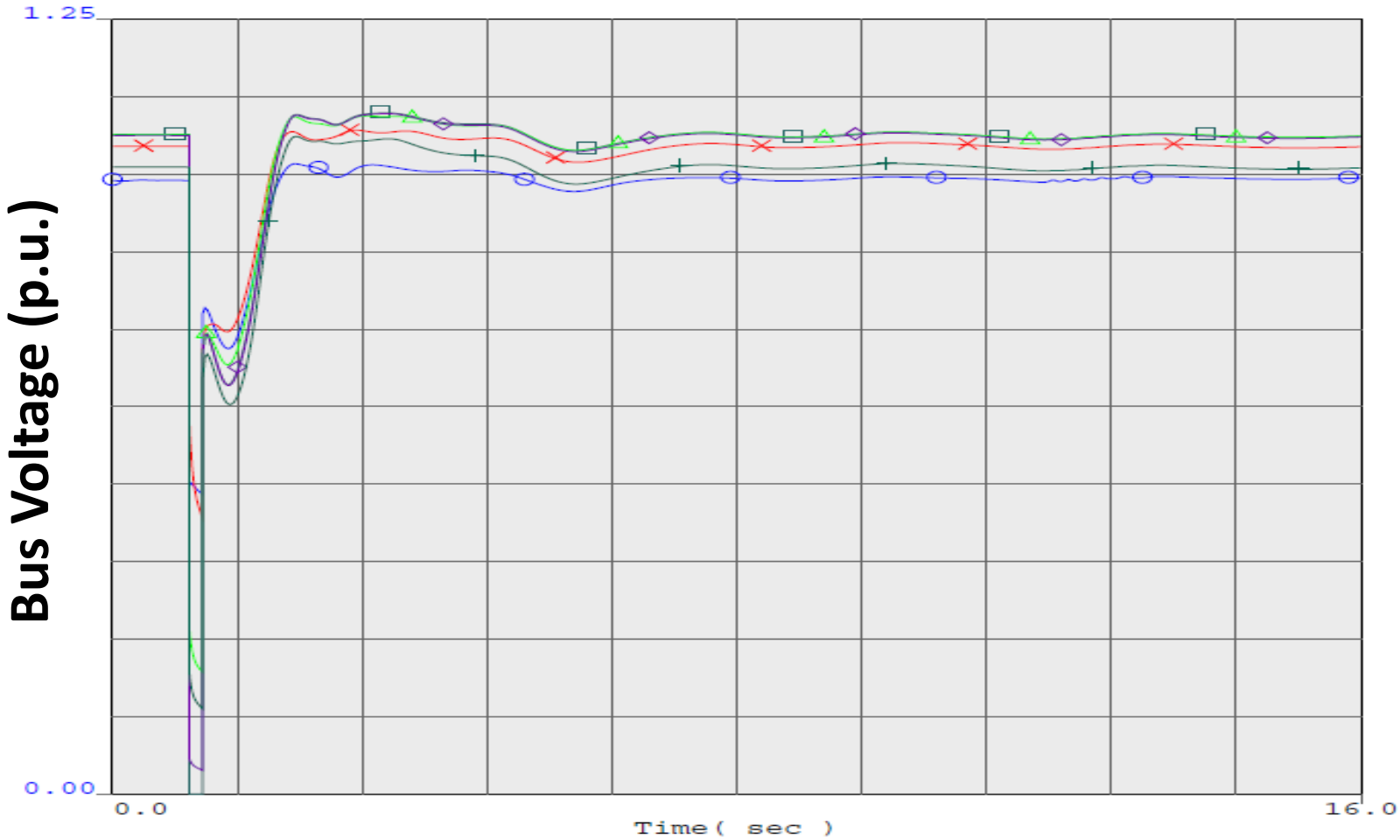


Coal Reduction Scenario

- 2019 Arizona Coordinated Heavy Summer Base Case
- 1872 MW coal plant retirements assumed
- 1195 MW new gas units added
- 360 MW of new renewables added
- 317 MW balance from reduction in area interchange to California

CR Scenario

Fault at Largest Single Generating Unit, Loss of Unit



Baseline versus CR Scenario

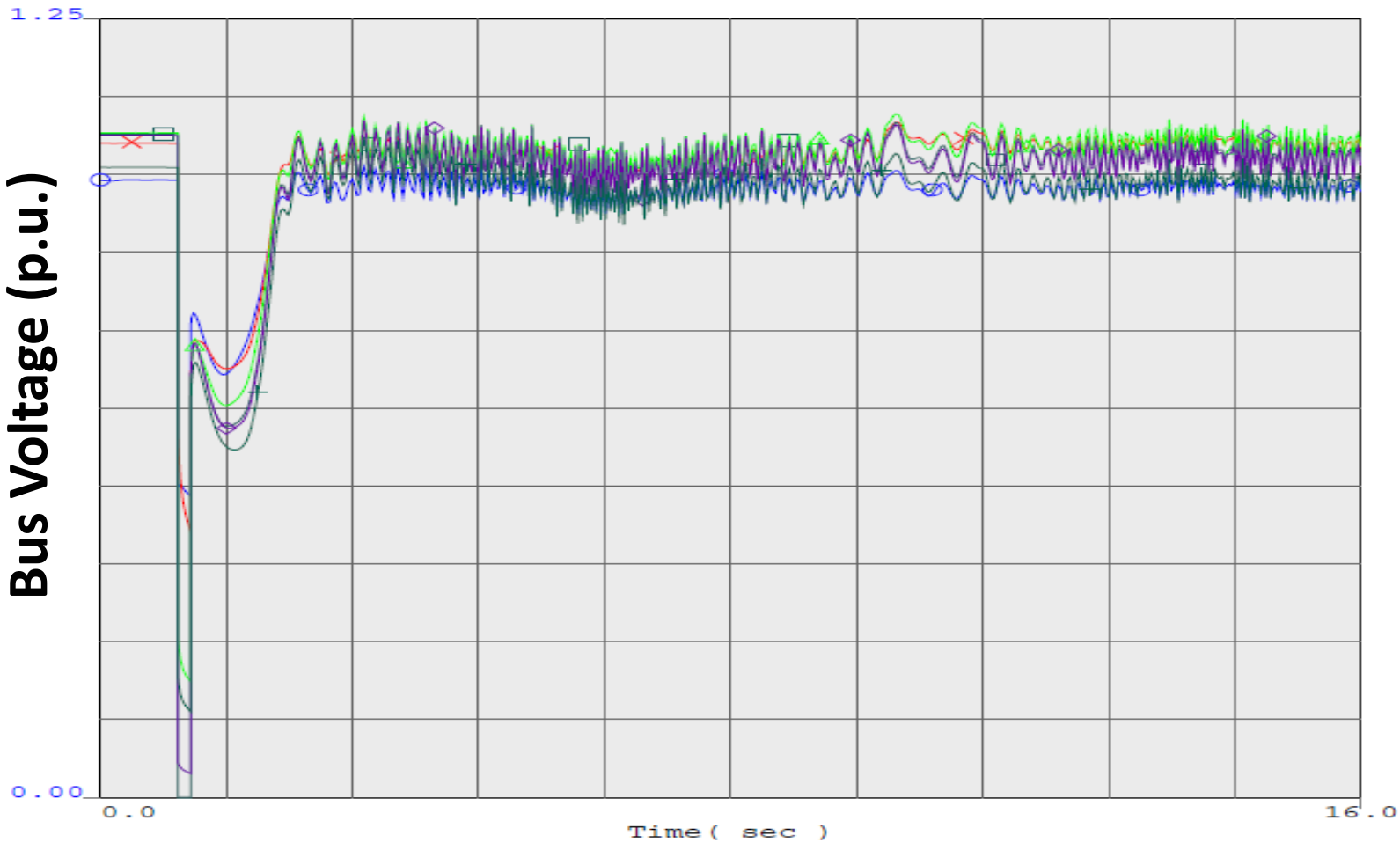
- Both are stable
- Coal reduction with gas performance is improved over Baseline
- Addition of gas units contributes to inertia and dynamic reactive capability
- Units located closer to load centers and fault locations improve performance

Coal Reduction Scenario with Renewables Added in Place of Gas

- 2019 Arizona Coordinated Heavy Summer Base Case
- 1872 MW coal plant retirements assumed
- 0 MW new gas units added
- 1674 MW of new renewables added
- 315 MW from reduction in area interchange to California
  - Assumes that California will add resources

CR Renewable (No Incremental Gas) Scenario

Fault at Largest Single Generating Unit, Loss of Unit



CR Gas versus CR Renewable Scenario

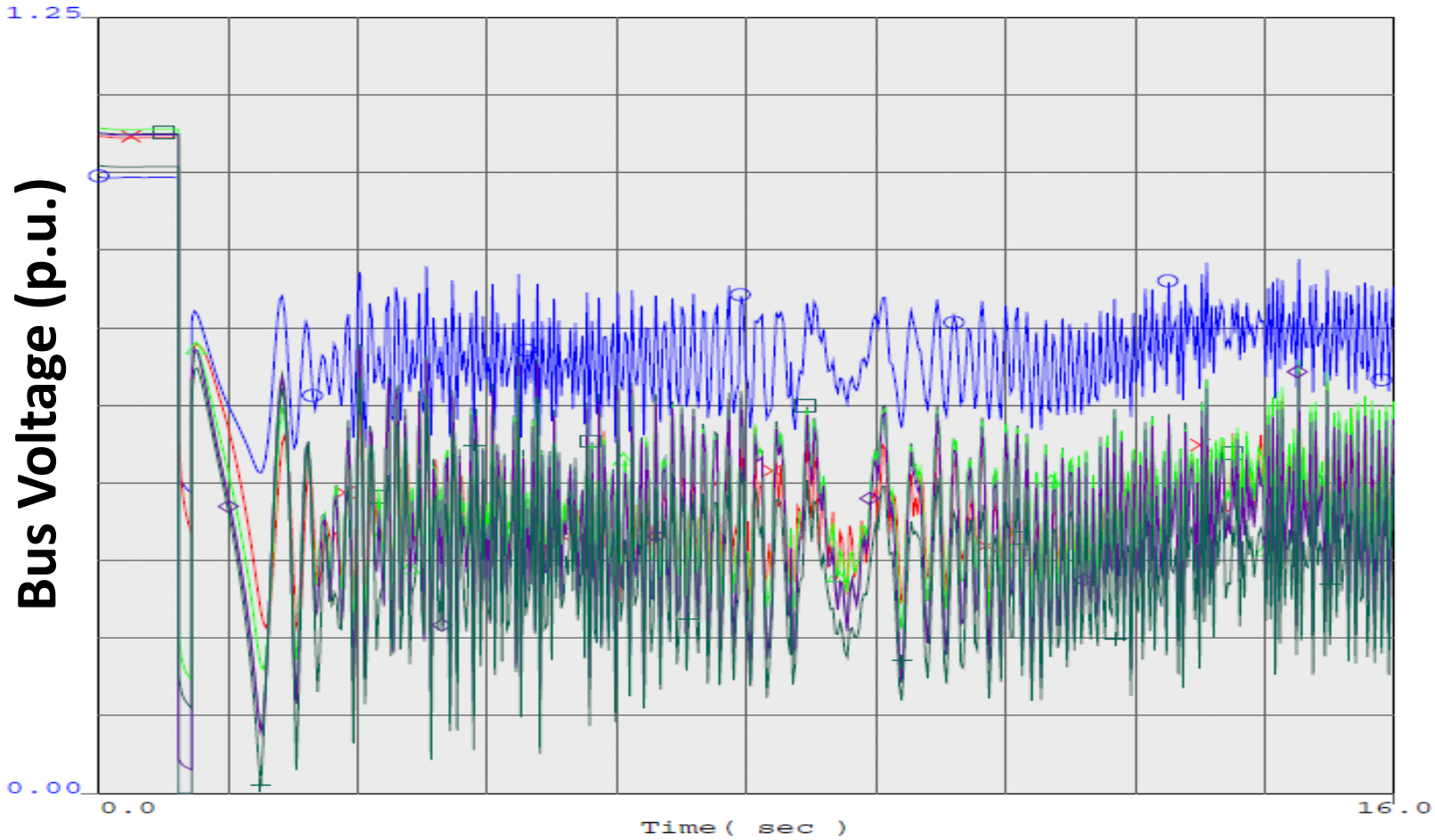
- Both are stable
- Coal reduction with gas performance is better than CR renewable scenario
- Addition of gas units contributes to inertia and dynamic reactive capability
- Renewables have less reactive capability

High Coal Reduction Renewable Sensitivity

- 2019 Arizona Coordinated Heavy Summer Base Case
- 4811 MW coal plant retirements assumed
- 0 MW new gas units added
- 3916 MW of new renewables added
  - Possibly higher renewables than would actually be available by 2019
- 895 MW balance from area interchange
  - Assumes that California will add resources

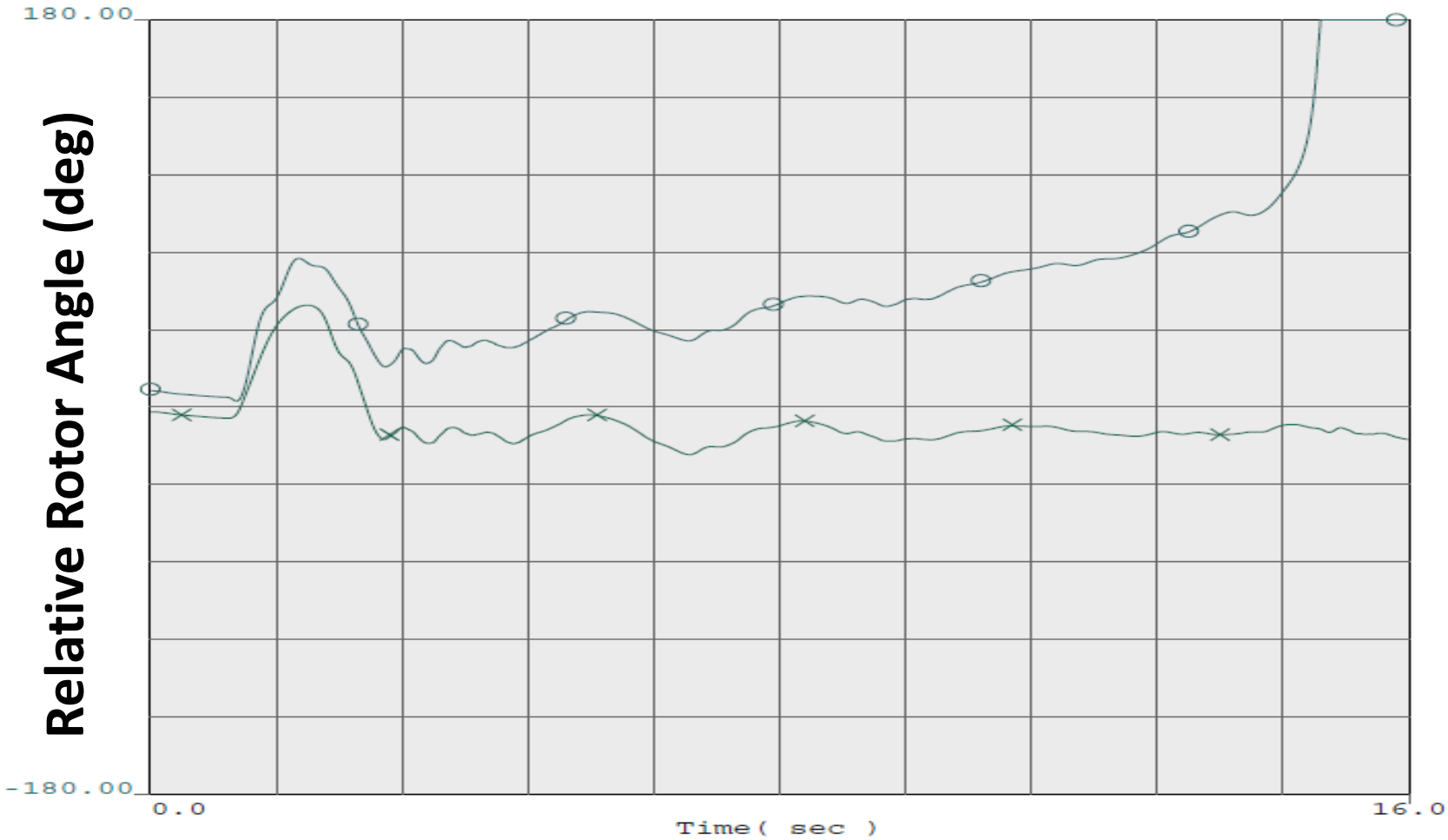
High CR & Renewable Sensitivity

Fault at Largest Single Generating Unit, Loss of Unit



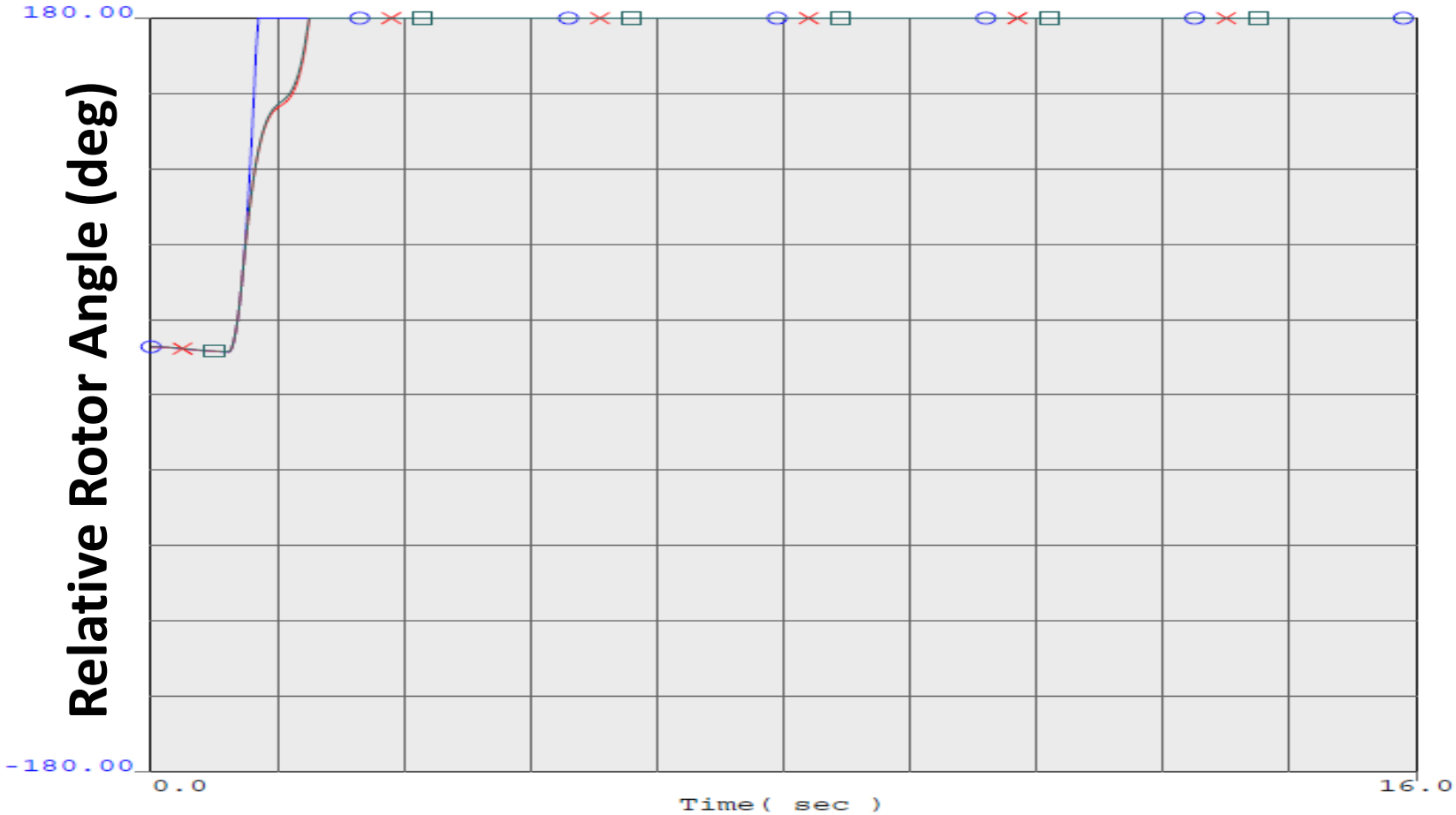
High CR & Renewable Sensitivity

Fault at Largest Single Generating Unit, Loss of Unit



High CR & Renewable Sensitivity

Fault at Largest Single Generating Unit, Loss of Unit



High CR & Renewable Sensitivity

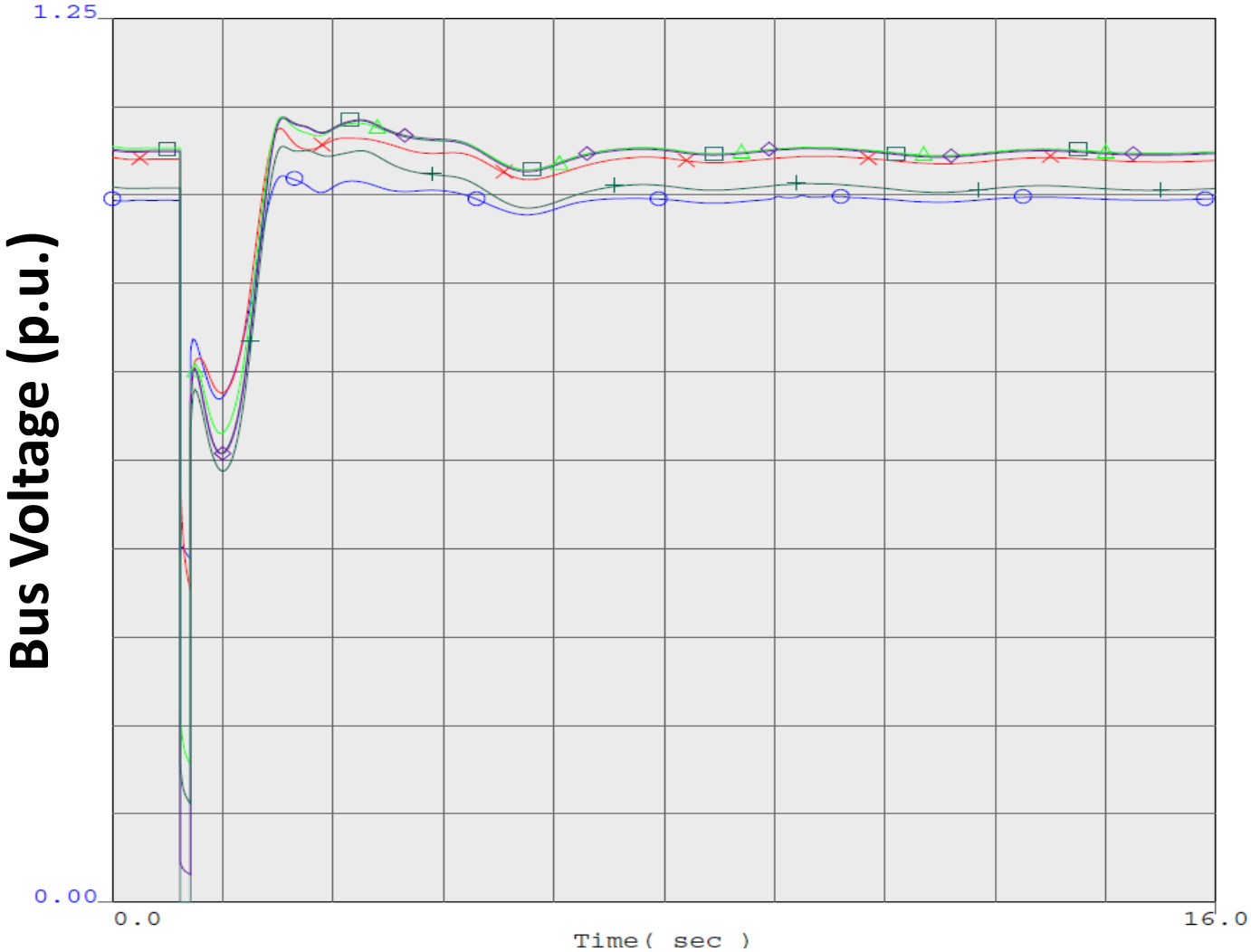
- Bus voltage unstable
- Large loss of coal plant inertia and dynamic reactive power capability
- Renewables do not add inertia and have limited reactive capability
  - Rooftop assumed to operate at unity power factor
  - Utility scale PV have inverters with reactive capability
- This sensitivity case was based on assumed resources and locations

CR Sensitivity - High CR & Renewable

- Rotor angle oscillations are undamped
- Generators will eventually trip
- Can result in cascading failures

High CR with Gas and Renewable Sensitivity

Fault at Largest Single Generating Unit, Loss of Unit

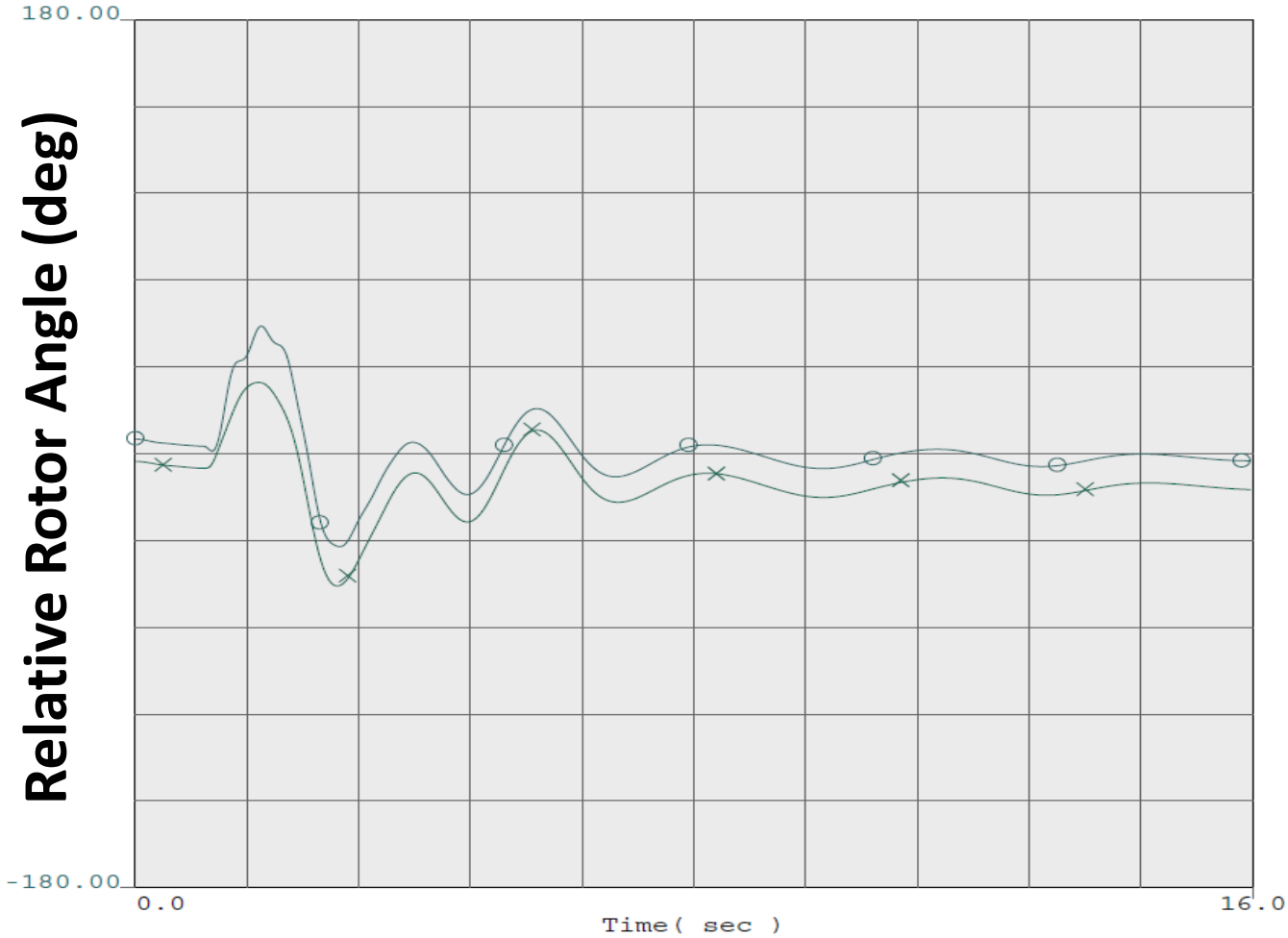


High Coal Reduction with Gas and Renewable Sensitivity

- 2019 Arizona Coordinated Heavy Summer Base Case
- 4811 MW Coal Plant Retirements Assumed
- 1195 MW New Gas Units Added
- 25 MW addition of SAN JUAN 4
- 2701 MW of New Renewables Added
- 893 MW balance from reduction in area interchange to California
  - Assumes that California will add resources

High CR & Gas Renewable Sensitivity

Fault at Largest Single Generating Unit, Loss of Unit



High CR & Gas/Renewable Sensitivity Generator Relative Rotor Angle

- Rotor angle oscillations are damped
- Bus voltages are stable and similar to baseline scenario
- Addition of the planned gas units eliminates stability issues

Issues Requiring Further Research

- Inertia versus Voltage Support (added gas resources)
- Observed high voltage issues on 500kV system in Four Corners area
  - Possibly due to shutting down coal units resulting in reduced loading on lines (line charging) and losing voltage regulation capability
- Impacts on Major Paths
- Impacts of Renewable intermittency
- Impacts of intraregional and Interregional power transfer

Conclusions

- There is a limit to the amount of coal plants that may be shut down while maintaining reliable system operation
- The limit to the amount of coal capacity that may be reduced is influenced by gas fired replacement capacity
- The amount of renewable resources that may be integrated is dependent upon addition of gas fueled generation, or other resources that compensate for loss of inertia and dynamic reactive capability
- A question to consider: "Is replacing coal capacity with an appropriate ratio of gas/renewables the only solution?"
  - Decisions related to coal plant shutdowns within the five-year planning horizon could limit options for the future
  - Should we take a little more time to come up with a more comprehensive regional / interregional strategy?

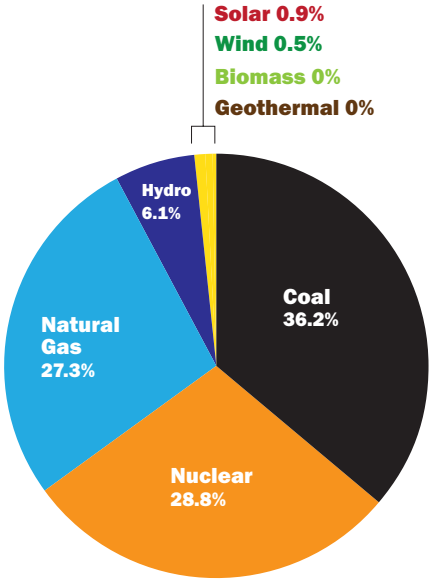
Recommendations

- Investigate developing a regional coal reduction study as a WestConnect scenario to identify regional transmission needs that may be met by regional transmission or non-transmission alternative projects
  - Coordinate with CAISO, NTTG and CG to the extent that interregional projects may be submitted
- Coordinate with TEPPC on Interconnection-wide studies
- Coordinate with SPP on comments to the EPA
- Develop SWAT study plan and scope for Phase 2:
  - Expand scope to include California
  - Spring season analysis
  - Path Rating impacts

EXHIBIT 12

ENERGY MIX CHART

Comparison of CO_2 emissions (lbs.) / state electricity generation in megawatt-hour (MWh)

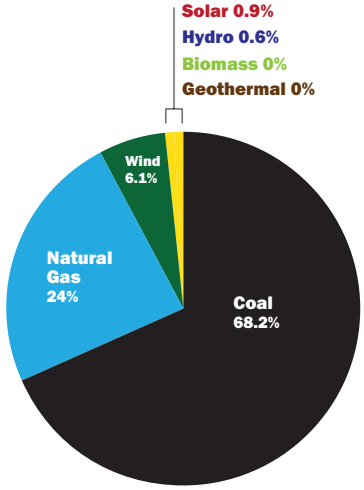


ARIZONA

REDUCTION: 51.7%

GOAL: 702 lbs./MWh

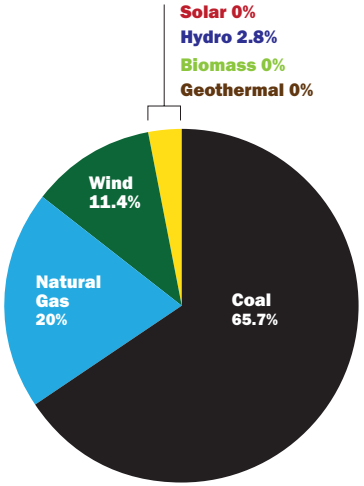
2012 Actual: 1,453 lbs./MWh



NEW MEXICO: 34.0% REDUCTION

2030 GOAL: 1,048 lbs./MWh

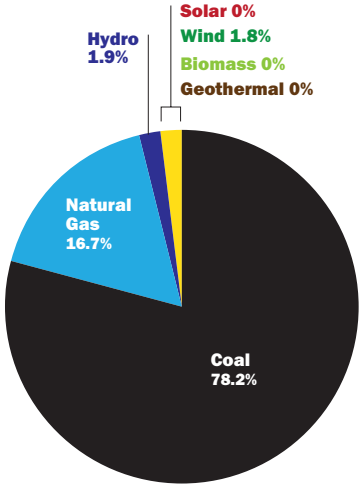
2012 Actual: 1,586 lbs./MWh



COLORADO: 35.4% REDUCTION

2030 GOAL: 1,108 lbs./MWh

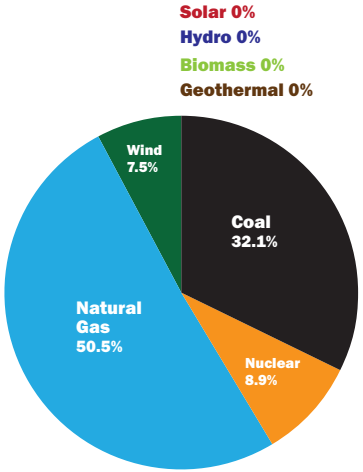
2012 Actual: 1,714 lbs./MWh



UTAH: 27.1% REDUCTION

2030 GOAL: 1,322 lbs./MWh

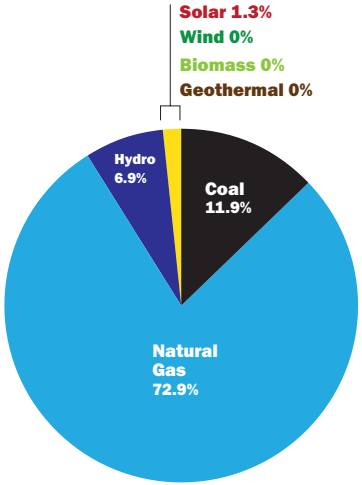
2012 Actual: 1,813 lbs./MWh



TEXAS: 39.1% REDUCTION

2030 GOAL: 791 lbs./MWh

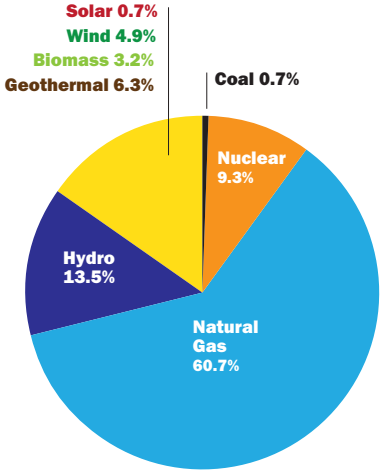
2012 Actual: 1,298 lbs./MWh



NEVADA: 34.5% REDUCTION

2030 GOAL: 647 lbs./MWh

2012 Actual: 988 lbs./MWh



CALIFORNIA: 23.1% REDUCTION

2030 GOAL: 537 lbs./MWh

2012 Actual: 698 lbs./MWh

Source: http://cleanpowerplanmaps.epa.gov/CleanPowerPlan/

Publication Number: C-14-28