BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB BURNS, Chairman
BOYD DUNN
SANDRA D. KENNEDY
JUSTIN OLSON
LEA MÁRQUEZ PETERSON

IN THE MATTER OF POSSIBLE MODIFICATIONS TO THE COMMISSION'S ENERGY RULES	**DOCKET NO. RU-00000A-18-0284** **Joint Stakeholder Proposal for New Energy Rules**

I. Introduction

The following comments are provided by American Council for an Energy-Efficient Economy, Arizona Faith Network, Arizona Interfaith Power and Light, Arizona Solar Energy Industries Association (AriSEIA), Arizona Public Health Association, Black Mesa Water Coalition, CHISPA Arizona, Conservative Alliance for Solar Energy (CASE), Diné C.A.R.E., E4TheFuture, Elders Climate Action, Environment Arizona Research & Policy Center, Natural Resources Defense Council, Our Mother of Sorrows Catholic Church, Physicians for Social Responsibility, Sierra Club, Solar Energy Industries Association

(SEIA), Solar United Neighbors, Southwest Energy Efficiency Project (SWEEP), Sunrun, Tó Nizhóní Ání, Tucson 2030 District, Vote Solar, Western Grid Group, and Western Resource Advocates (WRA) (together the "Joint Stakeholders") regarding possible modifications to the Commission's energy rules. As several stakeholders indicated in their comments to this proceeding,[1] the report provided by Commission Staff on April 25, 2019 and updated on July 2, 2019, appears to move Arizona energy policy backward — not forward — by eliminating requirements for renewable energy and energy efficiency, as well as combining the Renewable Energy Standard and Tariff ("REST"), Electric Energy Efficiency Standard ("EEES"), and Resource Planning and Procurement ("RPP") rules without strengthening or improving the accountability and transparency of the Commission's Integrated Resource Planning ("IRP") process.

The REST and EEES rules, both individually and collectively, have provided substantial benefits to the state and utility ratepayers in the form of cost savings; reduced water use; tens of thousands of in-state, family-wage jobs; economic development; and environmental benefits. These rules have been instrumental in ensuring that the most cost-effective resources are procured by utilities. As these rules have been effective and are functional, we recommend extending and improving upon them as the best method to provide continued benefits to ratepayers and the electricity system — rather than eliminating them and starting from scratch.

In response, the Joint Stakeholders have developed this comprehensive proposal modifying the Commission's existing rules and adding a clean energy focused standard. These comments serve as a summary and introduction to the Joint Stakeholder Rules and are accompanied by specific language for each modification in both clean and redline format. The intention of the Joint Stakeholder Rules is to provide a comprehensive alternative to the April 25th and July 2nd Staff Reports that addresses many of the proposals and ideas put

[1] See Comments of Western Resource Advocates, Western Grid Group, Vote Solar and Sierra Club filed May 29, 2019, in Docket No. RU-00000A-18-0284, https://docket.images.azcc.gov/0000198308.pdf

forth by Commissioners, as well as the interests of the groups who have collaborated on this effort.

As described in detail below, the Joint Stakeholder Rules include enforceable standards for the following:

- 100% clean energy by 2045,
- 50% renewable energy by 2030,
- 10% distributed generation by 2030, and
- 35% cumulative energy efficiency savings by 2030.

The Joint Stakeholder Rules also move Arizona toward a more comprehensive IRP process that provides for more effective stakeholder engagement and ensures greater accountability, while preserving the RPP rules as separate from the others.

Finally, the Joint Stakeholder Rules recognize the importance of supporting a just transition for communities impacted by power plant closure by encouraging clean energy investment on Tribal Lands.

Collectively, the Joint Stakeholder Rules are designed to ensure that:

- There is continued progress and accountability toward clean energy investment by Arizona's regulated utilities.
- Arizona's regulated utilities pursue near-term actions focused on investing in clean energy resources that are local and cost-effective.
- Investment in new resources is targeted toward those resources that are less likely to introduce future stranded costs.
- Arizona prioritizes clean energy investment that creates in-state jobs, supports communities impacted by power plant closure, capitalizes on Arizona's superior solar resource, and that improves local air quality and public health.

The Joint Stakeholders are appreciative of the leadership demonstrated by the Commission in addressing these complex and important issues. This proposal addresses many aspects of the proposals put forth by Chairman Bob Burns, Commissioner Sandra Kennedy, Commissioner Boyd Dunn, and former Commissioner Andy Tobin.

II. Clean Energy Standard

The Joint Stakeholder Rules contain a new standard of 100% clean energy by 2045. This requirement puts Arizona on the path towards a zero-carbon energy system and is consistent with policies being developed across the Western United States. A standard of 100% clean energy by 2045 is achievable and necessary to address the impacts of climate change. The current energy rules do not contain a clean energy standard and, as such, the Joint Stakeholder Rules create a new policy for measurement and compliance.

Under the Joint Stakeholder Rules, Clean Energy Standard compliance would be measured using a mass-based regulatory structure that would maximize flexibility in meeting the Standard by focusing on carbon content rather than any specific technology. A baseline carbon emissions rate would be set based on an average of 2016-2018 levels and decreased progressively until the requirement of 100% clean by 2045 is achieved. By including a Clean Energy Standard in addition to an update to the REST and EEES, the Joint Stakeholder Rules provide value and flexibility to achieve Arizona's energy future.

III. Renewable Energy Standard

Arizona's current REST of 15% by 2025 was adopted in 2006 — over a decade ago. Arizona's leadership in renewable energy policy spurred incredible entrepreneurship and technological innovation. At that time renewables were a relatively nascent technology and investments made in renewables have brought us to the place we are today. Renewable energy from solar and wind are some of the lowest cost energy resources available. With continued policy leadership, battery storage will improve the ability for renewable energy to match load, enabling higher penetration at lower costs, boosting the state's economy, improving Arizona's air quality, and reducing water consumption from power generation.

As a result, the Joint Stakeholder Rules include an enforceable standard for 50% renewable energy by 2030. Together with the Clean Energy Standard, this proposal would make Arizona competitive with nearly every other state in the West.[2] The Joint Stakeholder Rules also contain updates to the existing REST that increase the required renewable energy percentages beginning in 2020 until 50% renewable energy by 2030 is achieved.

IV. Distributed Energy Requirement

The current REST includes a requirement for distributed generation ("DG") in section R14-2-1805. This requirement is often called the "DG carve-out." The current DG carve-out requires that 30% of the existing 15% REST be satisfied by obtaining Renewable Energy Credits ("RECs") from distributed energy resources. In 2025 this requirement amounts to 4.5% of retail sales. Half of this carve-out is required to come from residential applications and the other half is required to come from non-residential, non-utility applications. When this provision was originally enacted, Arizona offered upfront incentive payments to customers installing DG. In exchange for the incentive payment, DG customers provided the RECs associated with their DG system production to the utility for use in complying with the REST and the DG carve-out. Since incentives have expired, participation in DG has continued to grow in Arizona, but the utilities are no longer receiving RECs for new DG. No alternative method for REC transfer has developed resulting in the need to request waivers from this provision of the current REST.

As Arizona updates the REST, the DG carve-out should be updated in order to accommodate the current situation in which the RECs associated with DG are not provided to the utility, and to ensure that customers are provided the opportunity to participate in clean energy development in Arizona. To accomplish these goals, the Joint Stakeholders propose an updated Distributed Renewable Energy Requirement ("DRER"). The DRER will not be a carve-out of the updated REST, but rather a parallel program under which

---

[2] The following standards have been adopted: Nevada: 50% renewable by 2030 and 100% clean by 2050; New Mexico: 50% renewable by 2030, 80% renewable by 2040, and 100% zero-carbon by 2045; Oregon: 50% renewable by 2040; Washington: 100% clean by 2045; California: 100% clean energy by 2045.

10% of total retail sales will be required to come from distributed generation by 2030.[3] The requirement will begin at 4% in 2020 and will increase by six tenths of one percent each year until 2030 when the 10% requirement is reached. DG resources that are eligible for the DRER must have a nameplate capacity of 50 kW or less.[4] Compliance with the DRER will be measured based on DG production captured by the dedicated production meters installed by the utility at the customer's premise.[5]

The proposed DRER is reasonable and conservative. The initial target of 4% in 2020 is less than current penetration levels for Arizona Public Service Company (APS), Tucson Electric Power (TEP), and UNS Electric.[6] Prior to the end of net metering, APS projected DG penetration as high as 18% in 2030[7]—a value significantly higher than the proposed requirement of 10% in 2030. As Arizona has moved away from retail rate net metering to an export credit rate, growth in DG is expected to slow significantly. Adoption of the DRER will ensure that there remains a viable path for customer participation in Arizona's clean energy future.

As utilities plan to meet the DRER, they should promote the development of customer-sited battery storage in combination with and in addition to DG. Such goals can be achieved through rate design and incentives, including compensation mechanisms for the utilization of Distributed Renewable Energy Resources to provide services in support of power system stability and power quality including "bring your own device" tariffs that compensate service aggregators for the coordination, operation, and dispatch of multiple customer-sited battery storage and DG systems.

---

[3] For purposes of the DRER retail sales will be measured inclusive of the solar production that is produced and consumed behind the meter.
[4] Community Distributed Generation is not subject to this size limitation.
[5] Production from Distributed Renewable Energy Resources will not be eligible for compliance under the REST unless RECs associated with the production are obtained and retired.
[6] See APS docket No. E-1345A-18-0226, TEP docket No. E-01933A-18-0238, and UNSE docket No. E-04204A-18-0239.
[7] Arizona Public Service Company. 2017 Integrated Resource Plan filed in Compliance with R14-2-703. April 2017. Table F-2, page 211.

V. Energy Efficiency Requirement

Since 2010 the current EEES has saved Arizona ratepayers money, energy, capacity, and water; stimulated the local economy; and reduced air pollutants — all cost-effectively. Benefits have included:

- More than $1 billion in net economic benefits for all Arizona ratepayers;
- More than 14 billion gallons of water saved; and,
- Energy savings equivalent to the consumption of more than 500,000 Arizona homes.[8]

Energy efficiency is also Arizona's cheapest energy resource[9] and employs more than 40,000 people across the state.[10]

In order to reap the benefits of continued energy efficiency investment, the Joint Stakeholder Rules include an enforceable standard for 35% cumulative energy savings by 2030. The Joint Stakeholder Rules also contain updates to the existing EEES to reduce regulatory barriers to energy efficiency program deployment and comprehensiveness.

VI. Integrated Resource Planning Process Improvements

The Joint Stakeholders propose significant modifications to the RPP rules to address concerns about the current IRP process, including proposed changes that will increase the opportunity for stakeholder involvement, increase accountability, and improve transparency in utility planning.

---

[8] See 2010-2018 Annual Demand Side Management reports of Tucson Electric Power, Arizona Public Service Company, and UNS Electric filed with the Arizona Corporation Commission.

[9] According to Tucson Electric Power's 2017 Integrated Resource Plan, other resources cost substantially more including gas (at least 4-times more) and nuclear (at least 6-times more).

[10] Environmental Entrepreneurs, Energy Efficiency Jobs in America: Arizona: https://www.e2.org/wp-content/uploads/2018/09/ARIZONA-Dist.pdf

As the Commission is aware, the prior IRPs submitted by APS and TEP were heavily focused on the procurement of gas resources to the detriment of other resources including renewable energy, energy storage, energy efficiency, and demand response. The Commission ultimately did not acknowledge the utilities' IRPs, which resulted in a gap in resource planning and highlighted the need for process improvements.

The Joint Stakeholders have undertaken considerable effort to propose rules that are best suited to Arizona and that are based on lessons learned from and best practices for resource planning from around the country. In addition to outlining a more user-friendly process that will enhance reporting requirements, improve and facilitate meaningful stakeholder involvement, and enable critical transparency for stakeholders and the Commission into a utility's development of its IRP, the Joint Stakeholder Rules outline a process that details specific actions to be taken in the case that an IRP is determined to be deficient. Under the proposed process, utilities must help the Commission and stakeholders understand why an IRP represents the best deal for ratepayers and how the IRP analysis and action plan has changed since the last Commission IRP review. Finally, utilities must return to the Commission for guidance or an amendment when major changes impact an IRP or IRP action plan.

VII. Transition for Impacted Communities

The Commission has recently taken steps to acknowledge the responsibility of utilities to provide support for communities impacted by the retirement of conventional power plants. Indeed, the pending Recommended Opinion and Order in Docket Nos. E-01345A-16-0036 and E-01345A-16-0123 directs Arizona Public Service Company to develop an initial transition plan for communities that will be impacted by the closure of the Four Corners Power Plant.

In addition to establishing a just transition plan and fund, the Commission can also support just transition efforts by encouraging clean energy development that directly benefits impacted communities. For example, there is strong potential for solar and wind development on Navajo and Hopi Lands that, if developed, could help Arizona achieve clean energy outcomes while also helping these communities transition to new economic bases.

To that end, the Joint Stakeholder rules include provisions that direct utilities to consider and give a preference to clean energy development opportunities in communities impacted by conventional power plant closures, including on Tribal Lands.

VIII. Conclusions

The Joint Stakeholders appreciate this opportunity to comment on this important conversation and to provide our proposed rules for the Commission's consideration. We are interested in engaging further on these issues and would welcome the opportunity to present the Joint Stakeholder Rules to the Commission at an upcoming meeting or workshop.

APPENDIX A

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 7. RESOURCE PLANNING AND PROCUREMENT

Section

R14-2-701 Statement of Purpose

This Article lays out the requirements for a comprehensive and robust Integrated Resource Planning process. The Integrated Resource Plan ("IRP") will consider all reasonable resources to satisfy the demand for electricity services during a fifteen (15)-year planning period, taking into account both supply- and demand-side electric power resources. In broad terms, the IRP will include an assessment of the planning environment, a careful and detailed study of a range of future load forecasts, present generation resources, present demand resources, current investments in electricity conservation technologies, existing transmission and distribution facilities, and the relevant forecast and scenario analyses in support of a load-serving entity's selected resource plan. It will also contain a discussion of all applicable laws and regulations to ensure that the proposed Action Plan for the implementation of the selected resource plan complies with all laws and regulations of the Federal government and the State of Arizona.

The purpose of this Article is to ensure that the IRP serves as an adequate and useful tool to guarantee the orderly and integrated development of Arizona's electric power system, and to improve the system's reliability, resiliency, efficiency, and transparency, as well as the provision of electric power services at reasonable prices. The provisions established herein will guide the IRP process along lines that are consistent with the mandates for the Commission and following the electric power industry's best practices in integrated resource planning. This regulation, moreover, defines the terms related to the information required in the IRP, the procedures before the Commission, and the performance metrics guidelines and inducements that load-serving entities will follow after the Commission has evaluated and reviewed the IRP. The Commission will evaluate the IRP as well as each load-serving entity's performance thereafter in accordance with the provisions set forth in this regulation.

This regulation shall be interpreted in a way that promotes the highest public good and the protection of the interests of the residents of Arizona, and in such a way that the proceedings are carried out rapidly, justly, and economically.

R14-2-702~~1~~. Definitions

In this Article, unless otherwise specified:

1. "Action Plan" refers to a plan that identifies the specific needs and potential actions that a load-serving entity will perform during the first five (5) years of the Planning Period in order to implement the Preferred Resource Plan.
2~~1~~. "Acknowledgment" means a Commission determination, under R14-2-704, that an Integrated Resource Plan~~plan~~ meets the ~~basic~~ requirements of this Article.
3~~2~~. "Affiliated" means related through ownership of voting securities, through contract, or otherwise in such a manner that one entity directly or indirectly controls another, is directly or indirectly controlled by another, or is under direct or indirect common control with another entity.
4~~3~~. "All-source Request for Proposals" or "all-source RFP" means a process wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants. The RFP shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFP shall consider demand-side resources on equal footing as supply-side ones and shall not be limited to "dispatchable" resources.
5. "All-source Request for Information" or "all-source RFI" means a process wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants. The RFI shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFI shall consider demand-side resources on equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

6. "Benchmark" means to calibrate against a known set of values or standards.
7. "Book life" means the expected time period over which a power supply source will be available for use by a load-serving entity.
8. "Btu" means British thermal unit.
9. "Capacity" means the amount of electric power, measured in megawatts, that a power source is rated to provide.
10. "Capacity Expansion Model" refers to a computer model designed to seek a least cost, or "optimal", portfolio of electricity supply- and demand-side resources that meets the utility's load forecast, accounting for system constraints and the need to maintain the reliability of the system over the planning period in the Preferred Resource Plan.
11. "Capital costs" means the construction and installation cost of facilities, including land, land rights, structures, and equipment.
12. "Coincident peak" means the maximum of the sum of two or more demands that occur in the same demand interval, which demand interval may be established on an annual, monthly, or hourly basis.
13. "Commission" or "ACC" refers to the Arizona Corporation Commission.
14. "Customer class" means a subset of customers categorized according to similar characteristics, such as amount of energy consumed; amount of demand placed on the energy supply system at the system peak; hourly, daily, or seasonal load pattern; primary type of activity engaged in by the customer, including residential, commercial, industrial, agricultural, and governmental; and location.
15. "Decommissioning" means the process of safely and economically removing a generating unit from service.
16. "Demand management" means beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage.
17. "Derating" means a reduction in a generating unit's capacity.
18. "Discount rate" means the interest rate used to calculate the present value of a cost or other economic variable.
19. "Docket Control" means the office of the Commission that receives all official filings for entry into the Commission's public electronic docketing system.
20. "Emergency" means an unforeseen and unforeseeable condition that:
    a. Does not arise from the load-serving entity's failure to engage in good utility practices,
    b. Is temporary in nature, and
    c. Threatens reliability or poses another significant risk to the system.
21. "End use" means the final application of electric energy, for activities such as, but not limited to, heating, cooling, running an appliance or motor, an industrial process, or lighting.
22. "Energy losses" means the quantity of electric energy generated or purchased that is not available for sale to end users, for resale, or for use by the load-serving entity.
23. "Escalation" means the change in costs due to inflation, changes in manufacturing processes, changes in availability of labor or materials, or other factors.
24. "Generating unit" means a specific device or set of devices that converts one form of energy (such as heat or solar energy) into electric energy, such as a turbine and generator or a set of photovoltaic cells.
25. "Heat rate" means a measure of generating station thermal efficiency expressed in Btus per net kilowatt-hour and computed by dividing the total Btu content of fuel used for electric generation by the kilowatt-hours of electricity generated.
26. "Independent monitor" means a company or consultant that is not affiliated with a load-serving entity and that is selected to oversee the conduct of a competitive procurement process under R14-2-706.
27. "Integrated Resource Plan" or "IRP" means a plan that considers all reasonable resources to satisfy the demand for electric power services during a specific period of time, including those relating to the offering of electric power, whether existing, traditional, and/or new resources, and those relating to energy demand such as energy conservation and efficiency or demand response and localized energy generation by the customer, while recognizing the obligation of compliance with laws and regulations that constrain resource selection.
28. "Integration" means methods by which energy produced by intermittent resources can be incorporated into the electric grid.
29. "Intermittent resources" means electric power generation for which the energy production varies in response to naturally occurring processes like wind or solar intensity.
30. "Interruptible power" means power made available under an agreement that permits curtailment or cessation of delivery by the supplier.
31. "In-service date" means the date a power supply source becomes available for use by a load-serving entity.
32. "Load-serving entity" means a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined.
33. "Long-term" means having a duration of three or more years.
34. "Major change" means any new procurement effort or addition, retirement or modification of generation plant having a nameplate capacity of 50 megawatts or greater; the addition of pollution control equipment; the unanticipated termination of a Power Purchase Agreement; or other event, such as a major forest fire, as set forth by the Commission.
35. "Major Project" shall mean any project greater than 50 megawatts.
36. "Maintenance" means the repair of generation, transmission, distribution, administrative, and general facilities; replacement of minor items; and installation of materials to preserve the efficiency and working condition of facilities.
37. "Mothballing" means the temporary removal of a generating unit from active service and accompanying storage activities.
38. "Operate" means to manage or otherwise be responsible for the production of electricity by a generating facility, whether that facility is owned by the operator, in whole or in part, or by another entity.
39. "Participation rate" means the proportion of customers who take part in a specific program.

40. "Planning Period" means the fifteen (15)-year period in an Integrated Resource Plan for which resources must be planned to meet customer load requirements.
41. "Planning Reserve Margin" refers to the reserve margin required to operate a load-serving entity's system reliably.
42. "Preferred Resource Plan" means a portfolio of resource additions selected by a load-serving entity from amongst those evaluated in the IRP representing the best performing resource mix to be implemented in the Action Plan.
43. "Probabilistic analysis" means a systematic evaluation of the effect, on costs, reliability, or other measures of performance, of possible events affecting factors that influence performance, considering the likelihood that the events will occur.
44. "Production cost" means the variable operating costs and maintenance costs of producing electricity through generation, including fuel cost, plus the cost of purchases of power sufficient to meet demand.
45. "Reference Case" refers to the forecast of load and associated system requirements, commodity prices, capital costs and risks representing a load-serving entity's best understanding of expected circumstances or median probability outcomes.
46. "Refurbish" means to make major changes, more extensive than maintenance or repair, in the power production, transmission, or distribution characteristics of a component of the power supply system, such as by changing the fuels that can be used in a generating unit or changing the capacity of a generating unit.
47. "Reliability" means a measure of the ability of a load-serving entity's generation, transmission, or distribution system to provide power without failures, measured to reflect the portion of time that a system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.
48. "Renewable energy resource" means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
49. "Reserve requirements" means the capacity that a load-serving entity must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, emergencies, system operating requirements, and reserve sharing arrangements.
50. "Reserve sharing arrangement" means an agreement between two or more load-serving entities to provide backup capacity.
51. "Resource Plan" refers to a selection of supply-side, demand-side, and transmission resources that best serves a load-serving entity's needs under a given forecast scenario.
52. "Resource planning" means integrated supply and demand analyses completed as described in this Article.
53~~40~~. "RFP" means request for proposals.
54. "Self generation" means the production of electricity by an end user.
55. "Sensitivity analysis" means a systematic assessment of the degree of response of costs, reliability, or other measures of performance to changes in assumptions about factors that influence performance.
56. "Short-term" means having a duration of less than three years.
57. "Socioeconomic effects" means changes in the social and economic environments, including, for example, job creation, effects on local economics, geographical concentration of persons and structures, concentration of investment capital, and the ability of low-income and rental households to receive conservation services.
58. "Spinning reserve" means the capacity a load-serving entity must maintain connected to the system and ready to deliver power promptly in the event of an unexpected loss of generation source, expressed as a percentage of peak load, a percentage of the largest generating unit, or in fixed megawatts.
59. "Staff" means individuals working for the Commission's Utilities Division, whether as employees or through contract.
60. "Third-party independent energy broker" means an entity, such as Prebon Energy or Tradition Financial Services, that facilitates an energy transaction between separate parties without taking title to the transaction.
61. "Third-party online trading system" means a computer-based marketplace for commodity exchanges provided by an entity that is not affiliated with the load-serving entity, such as the Intercontinental Exchange, California Independent System Operator, or New York Mercantile Exchange.
62. "Total cost" means all capital, operating, maintenance, fuel, and decommissioning costs, plus the costs associated with mitigating any adverse environmental effects, incurred by end users, load-serving entities, or others, in the provision or conservation of electric energy services.

R14-2-70~~2~~3. Applicability

A. This Article applies to each load-serving entity, whether the power generated is for sale to end users or is for resale.
B. An electricity public service corporation that becomes a load-serving entity by increasing its generating capacity to at least 50 megawatts combined shall provide written notice to the Commission within 30 days after the increase and shall comply with the filing requirements in this Article within two years after the notice is filed.
C. The Commission may, by Order, exempt a load-serving entity from complying with any provision in this Article, or the Article as a whole, upon determining that:
   1. The burden of compliance with the provision, or the Article as a whole, exceeds the potential benefits to customers in the form of cost savings, service reliability, risk reductions, or reduced environmental impacts that would result from the load-serving entity's compliance with the provision or Article; and
   2. The public interest will be served by the exemption.
D. A load-serving entity that desires an exemption shall submit to Docket Control an application that includes, at a minimum:
   1. The reasons why the burden of complying with the Article, or the specific provision in the Article for which exemption is requested, exceeds the potential benefits to customers that would result from the load-serving entity's compliance with the provision or Article;

2. Data supporting the load-serving entity's assertions as to the burden of compliance and the potential benefits to customers that would result from compliance; and
3. The reasons why the public interest would be served by the requested exemption.

~~E. A load-serving entity shall file with Docket Control, within 120 days after the effective date of these rules, the documents that would have been due on April 1, 2010, under R14-2-703(C), (D), (E), (F), and (H) had the revisions to those subsections been effective at that time.~~

R14-2-7044~~3~~. Load-serving Entity Annual Reporting Requirements

A. Demand-Side Data: A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of demand-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:

1. Hourly demand for the previous calendar year, disaggregated by:
   a. Sales to end users;
   b. Sales for resale;
   c. Energy losses; and
   d. Other disposition of energy, such as energy furnished without charge and energy used by the load-serving entity;
2. Coincident peak demand (megawatts) and energy consumption (megawatt-hours) by month for the previous 10 years, disaggregated by customer class;
3. Number of customers by customer class for each of the previous 10 years; and
4. Reduction in load (kilowatt and kilowatt-hours) in the previous calendar year due to existing demand management measures, by type of demand management measure.

B. Supply-Side Data: A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of supply-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:

1. For each generating unit and purchased power contract for the previous calendar year:
   a. In-service date and book life or contract period;
   b. Type of generating unit or contract;
   c. The load-serving entity's share of the generating unit's capacity, or of capacity under the contract, in megawatts;
   d. Maximum generating unit or contract capacity, by hour, day, or month, if such capacity varies during the year;
   e. Annual capacity factor (generating units only);
   f. Average heat rate of generating units and, if available, heat rates at selected output levels;
   g. Average fuel cost for generating units, in dollars per million Btu for each type of fuel;
   h. Other variable operating and maintenance costs for generating units, in dollars per megawatt hour;
   i. Purchased power energy costs for long-term contracts, in dollars per megawatt-hour;
   j. Fixed operating and maintenance costs of generating units, in dollars per megawatt;
   k. Demand charges for purchased power;
   l. Fuel type for each generating unit;
   m. Minimum capacity at which the generating unit would be run or power must be purchased;
   n. Whether, under standard operating procedures, the generating unit must be run if it is available to run;
   o. Description of each generating unit as base load, intermediate, or peaking;
   p. Environmental impacts, including air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt-hour) for carbon dioxide, nitrogen oxides, sulfur dioxide, mercury, particulates, and other air emissions subject to current or expected future environmental regulation;
   q. Water consumption quantities and rates; and
   r. Tons of coal ash produced per generating unit;
2. For the power supply system for the previous calendar year:
   a. A description of generating unit commitment procedures;
   b. Production cost;
   c. Reserve requirements;
   d. Spinning reserve;
   e. Reliability of generating, transmission, and distribution systems;
   f. Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts; and
   g. Energy losses;
3. The capacity, type, location(s), and expected term of demand-side resources offered in the load-serving entity's service area for the previous calendar year:
   a. By or on behalf of the utility;
   b. Through government-sponsored programs; or
   c. Through ~~level of~~ self generation ~~in the load-serving entity's service area for the previous calendar year~~; and
4. An explanation of any resource procurement processes used by the load-serving entity during the previous calendar year that did not include use of an RFP, including the exception under which the process was used.

C. ~~A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following items of load data and analyses, which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing:~~

1. ~~Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses;~~
2. ~~Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures; and~~
3. ~~Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including~~
~~-a description of how the forecasts were benchmarked and~~
~~-justifications for selecting the methods and assumptions used~~

;

D. ~~A load-serving entity shall, by April 1 of each even year, file with Docket Control the following prospective analyses and plans, which shall compare a wide range of resource options and take into consideration expected duty cycles, cost projections, other analyses required under this Section, environmental impacts, and water consumption and may include a reference to the last filing made under this subsection for each item for which there has been no change since the last filing:~~

1. ~~A 15-year resource plan, providing for each year:~~
   a. ~~Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment;~~
   b. ~~Projected data for each of the items listed in subsection (B)(2), for the power supply system;~~
   c. ~~The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period;~~
   d. ~~The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source;~~
   e. ~~If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected:~~
      i. ~~Identification of each power source or generating unit involved;~~
      ii. ~~The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and~~
      iii. ~~The reasons for each discontinuation, decommissioning, mothballing, or derating;~~
   f. ~~The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period;~~
   g. ~~An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona; and~~
   h. ~~Cost analyses and cost projections, including the cost of compliance with existing and expected environmental regulations;~~
2. ~~Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked;~~
3. ~~A description of:~~
   a. ~~Each potential power source that was rejected;~~
   b. ~~The capital costs, operating costs, and maintenance costs of each rejected source; and~~
   c. ~~The reasons for rejecting each source;~~
4. ~~A 15-year forecast of self generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);~~
5. ~~Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures;~~
6. ~~A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified under subsections (D)(4) and (5);~~
7. ~~Documentation of the analysis of the self generation under subsections (D)(4) through (6);~~
8. ~~A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio;~~
9. ~~A calculation of the benefits of generation using renewable energy resources;~~
10. ~~A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery;~~
11. ~~Analysis of integration costs for intermittent resources;~~
12. ~~A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;~~
13. ~~Data to support technology choices for supply-side resources;~~
14. ~~A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure:~~
    a. ~~How and when the program or measure will be implemented;~~

~~b. The projected participation level by customer class for the program or measure;~~

~~c. The expected change in peak demand and energy consumption resulting from the program or measure;~~

~~d. The expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure;~~

~~e. The expected societal benefits, societal costs, and cost-effectiveness of the program or measure;~~

~~f. The expected life of the measure; and~~

~~g. The capital costs, operating costs, and maintenance costs of the measure, and the program costs;~~

~~15. For each demand management measure that was considered but rejected:~~

~~a. A description of the measure;~~

~~b. The estimated change in peak demand and energy consumption from the measure;~~

~~c. The estimated cost-effectiveness of the measure;~~

~~d. The capital costs, operating costs, and maintenance costs of the measure, and the program costs; and~~

~~e. The reasons for rejecting the measure;~~

~~16. Analysis of future fuel supplies that are part of the resource plan; and~~

~~17. A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.~~

~~E. A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following analyses and plan:~~

~~1. Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:~~

~~a. Demand forecasts;~~

~~b. The costs of demand management measures and power supply;~~

~~c. The availability of sources of power;~~

~~d. The costs of compliance with existing and expected environmental regulations;~~

~~e. Any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations;~~

~~f. Changes in fuel prices and availability;~~

~~g. Construction costs, capital costs, and operating costs; and~~

~~h. Other factors the load-serving entity wishes to consider;~~

~~2. A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects; and~~

~~3. A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1).~~

~~F. A load-serving entity shall, by April 1 of each even year, file with Docket Control a 15-year resource plan that:~~

~~1. Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply- and demand-side options;~~

~~2. Will result in the load-serving entity's reliably serving the demand for electric energy services;~~

~~3. Will address the adverse environmental impacts of power production;~~

~~4. Will include renewable energy resources to meet or exceed the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity:~~

~~Calendar Year~~	~~Percentage of Retail kWh Sold During Calendar Year~~
~~2010~~	~~2.5%~~
~~2011~~	~~3.0%~~
~~2012~~	~~3.5%~~
~~2013~~	~~4.0%~~
~~2014~~	~~4.5%~~
~~2015~~	~~5.0%~~
~~2016~~	~~6.0%~~
~~2017~~	~~7.0%~~
~~2018~~	~~8.0%~~
~~2019~~	~~9.0%~~
~~2020~~	~~10.0%~~
~~2021~~	~~11.0%~~
~~2022~~	~~12.0%~~
~~2023~~	~~13.0%~~
~~2024~~	~~14.0%~~

~~after 2024~~	~~15.0%~~

5. ~~Will include distributed generation energy resources to meet or exceed the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement:~~

~~2007~~	~~5%~~
~~2008~~	~~10%~~
~~2009~~	~~15%~~
~~2010~~	~~20%~~
~~2011~~	~~25%~~
~~After 2011~~	~~30%~~

6. ~~Will address energy efficiency so as to meet any requirements set in rule by the Commission or in an order of the Commission;~~
7. ~~Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors;~~
8. ~~Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2) through (7) and the uncertainty of future costs; and~~
9. ~~Contains all of the following:~~
   a. ~~A complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized;~~
   b. ~~A comprehensive, self-explanatory load and resources table summarizing the plan;~~
   c. ~~A brief executive summary;~~
   d. ~~An index to indicate where the responses to each filing requirement of these rules can be found; and~~
   e. ~~Definitions of the terms used in the plan.~~

G. ~~A load-serving entity shall, by April 1 of each odd year, file with Docket Control a work plan that includes:~~
1. ~~An outline of the contents of the resource plan the load-serving entity is developing to be filed the following year as required under subsection (F);~~
2. ~~The load-serving entity's method for assessing potential resources;~~
3. ~~The sources of the load-serving entity's current assumptions; and~~
4. ~~An outline of the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan.~~

H. ~~With its resource plan, a load-serving entity shall include an action plan, based on the results of the resource planning process, that:~~
1. ~~Includes a summary of actions to be taken on future resource acquisitions;~~
2. ~~Includes details on resource types, resources capacity, and resource timing; and~~
3. ~~Covers the three-year period following the Commission's acknowledgment of the resource plan.~~

I. ~~A load-serving entity or interested party may provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.~~

J. ~~If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff shall request additional information from the load-serving entity, including the data used in the load-serving entity's analyses.~~

K. ~~Staff may request that a load-serving entity complete additional analyses to improve specified components of the load-serving entity's submissions.~~

L. ~~If a load-serving entity believes that a data-reporting requirement may result in disclosure of confidential business data or confidential electricity infrastructure information, the load-serving entity may submit to Staff a request that the data be submitted to Staff under a confidentiality agreement, which request shall include an explanation justifying the confidential treatment of the data.~~

M. ~~Data protected by a confidentiality agreement shall not be submitted to Docket Control and will not be open to public inspection or otherwise made public except upon an order of the Commission entered after written notice to the load-serving entity.~~

R14-2-705. Integrated Resource Planning Process

A. Planning Period; Effectiveness
1. The IRP shall consider a planning period of fifteen (15) years.
2. An IRP acknowledged by the Commission shall remain in effect until the acknowledgment of a subsequent IRP by the Commission, or until otherwise established by the Commission through resolution or order.
3. Any proposal for a new IRP, or any proposed update, review, or amendment to an existing IRP must be submitted to the Commission for evaluation and acknowledgment. An update, revision, or amendment to an IRP, in whole or in part, will not enter into effect until it is acknowledged by the Commission.

B. Schedule and Filing

1. By April 1 of every third year, each load-serving entity shall submit for Commission acknowledgment an IRP proposal in accordance with the provisions of this Article and applicable Commission resolutions and orders. In the case of a substantial change in the energy demand or group of resources, the Commission may order that the review of the next IRP be carried out before the three (3) years provided here to respond to and/or mitigate such changes. At any moment prior to the three-year filing requirement, a load-serving entity may submit a proposed update, amendment or review to an acknowledged IRP, as described in Section R14-2-708.
2. The filing of the IRP shall initiate a proceeding at the Commission pursuant to the provisions of this Article.

C. Integrated Resource Plan Filing Structure and Requirements

1. The IRP filing shall be comprised of a main body and accompanying technical appendices.
   a. The main body of the IRP shall be written as a coherent, stand-alone document designed to allow informed readers sufficient information to understand the process by which a load-serving entity conducts long-term resource planning and the key outcomes of that resource planning. The main body shall be organized into the following chapters:
      Part One – Introduction and Summary of Conclusions
      Part Two – Planning Environment
      Part Three – Load Forecast
      Part Four – Existing Resources
      Part Five – Resource Needs Assessment
      Part Six – New Resource Options
      Part Seven – Assumptions and Forecast
      Part Eight – Resource Plan Development
      Part Nine – Caveats and Limitations
      Part Ten – Work Plan
      Part Eleven – Action Plan
      Part Twelve – Other considerations or additional information, as required by the Commission through and order, that may address subjects related to integrated resource planning.
   b. The technical appendices of the IRP filing shall include ancillary information and descriptions required by this Article but not included in the main body of the IRP filing. The following technical appendices must be attached to the IRP filing:
      Appendix 1 – Transmission and Distribution Planning
      Appendix 2 – Prior Action Plan Implementation Status
      Appendix 3 – Renewable Energy Project Status
      Appendix 4 – Demand-Side Resources
      Appendix 5 – New and Existing Supply-Side Resource Supplemental Data
      Appendix 6 – Additional information, as required by the Commission through and order, that may address subjects related to integrated resource planning.
   c. The IRP filing shall specifically identify and include all references to external and internal source documents relied upon in the development of the proposed IRP.
      1. If a source document is publicly available on the Internet, a specific link (URL address) to the source document shall be provided.
      2. If a source document referenced by the load-serving entity in any portion of its IRP filing is not publicly available or readily accessible, an electronic copy of such source documents shall be provided along with the IRP filing.
      3. If a source document consists of a study, report, book, periodical, or other publication, not publicly available or readily accessible, the load-serving entity shall provide copies of the relevant pages from such source documents relied upon in the development of its proposed IRP. All pages which are necessary to understand the relevant pages in context shall be provided. Upon request, the load-serving entity shall make available the entirety of such source document. In the case such source documents are protected under federal copyright law, the load-serving entity shall make a reference to the documents used for the development of the proposed IRP.
   d. Work papers and models relied upon by the load-serving entity in the development of the IRP shall be filed concurrently with the IRP.
      1. Work papers which are available in electronic form shall be provided electronically in native format. All formulae and viable links shall be left intact.
      2. The load-serving entity shall, at a minimum, provide the following work papers to the Commission:
         i. Load Forecast Development work papers;
         ii. Fuel Price Forecast Development work papers;
         iii. Resource Plan modeling input files;
         iv. Resource Plan modeling output files as used by the load-serving entity;
         v. Any post-processing or analysis work papers used to assess the Resource Plan modeling output files, including financial models used to calculate the present value of revenue requirements, rate impacts, or other cost elements of the IRP;
         vi. Electronic, spreadsheet-based versions of all tables and figures as presented in the IRP.
   e. The load-serving entity shall provide access to the modeling software, including license to Staff of the model(s) they use, at a minimum, and to provide, as an addendum to the filing, inputs and outputs and/or saved run files from the models. Such access shall be adequate to enable the Commission to replicate the results and may include the load-serving entity

manipulating the computer model according to instructions or input from the Commission. Reasonable access shall also be provided to intervenors. If the load-serving entity seeks to limit access to the program or application to intervenors, the Commission will determine the appropriate access to the program or its output.

f. The load-serving entity shall use modeling software that meets the following criteria:

1. There are no technical or legal barriers to providing inputs and outputs of the model to stakeholders in a format legible to stakeholders;
2. The utility can provide the modeling parameters to stakeholders;
3. The software can reasonably model all types of resources, including wind, solar, and storage, including battery storage;
4. The software can model at hourly and sub-hourly timescales; and
5. The software is capable of modeling fixed resource retirement dates or optimizing resource retirement dates.

2. When filing its IRP, the load-serving entity shall simultaneously publish its IRPs in its full and complete form on the utility's website, which should be presented in an accessible and comprehensible way to the general public. The load-serving entity may only withhold information from reporting with Commission approval, under a protective order as provided in Section R14-2-707(D)(3), and stakeholders shall have a reasonable opportunity to challenge designations of information as confidential.

R14-2-706. Integrated Resource Plan Requirements

A load-serving entity shall, by April 1 of every third year, file with Docket Control a preliminary IRP. Consistent with Section R14-2-705(C) above, a load-serving entity's IRP must include the following:

A. Planning Environment: The IRP shall include a description of the various current laws, regulations, and other rules that might affect planning decisions, as well as any that are likely to be implemented during the course of the planning period.

1. This section shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time through the planning period.
2. This section shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the acknowledgment of the most recent IRP.

B. Load Forecast: The load-serving entity shall provide a compilation of peak electricity demand and annual electricity consumption forecasts for each year of the IRP planning period which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing.

1. The load forecasts will include the following items:

a. Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses;

b. The load-serving entity shall prepare at least three (3) baseline Load Forecasts to reflect a reasonable range of future uncertainties:

1. A reference case representing the load-serving entity's best understanding of expected circumstances or median probability outcomes;
2. A low case where customer electricity demand and consumption are significantly below utility median expectations through the planning period; and
3. A high case where customer electricity demand and consumption are significantly above utility median expectations through the planning period.

c. Disaggregation of the load forecast into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures;

d. Analysis and consideration of the impact of:

1. Existing demand-side resources, anticipated changes to rate design, building codes and standards, deployment of distributed generation, and other important factors on the load forecast;
2. Technical losses in the load forecast, including the extent to which the forecast includes the effects of current and planned technical loss reduction programs; and
3. Non-technical losses in the load forecast, including the extent to which the forecast includes the effects of current and planned non-technical loss reduction programs.

e. Historic peak demand and energy. Historic data shall be reported covering a ten (10)-year period prior to the first year of the IRP Planning Period and shall include:

1. The total annual electricity generation and sales for the utility and consumption for each customer class; and
2. The coincident peak electricity demand for the utility and each customer class.

f. Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

g. An evaluation of prior load forecasts provided in the most recent IRP, including:

1. Assessment of the annual accuracy of the previous forecasting including a comparison of forecasted versus actual data;
2. An explanation of the cause of any significant deviation (meaning more than 5%) between the previous forecasts and the actual annual peak demand and energy that occurred; and
3. An explanation of the impact that historic demand-side resources had on the prior load forecast.

2. The load forecasts will be conducted in accordance with the following criteria:
   a. A reasonable set of assumptions for economic and/or end use variables shall be included in the development of the long-term load forecasts.
   b. The load forecasts shall reflect normal weather conditions but must account for forecasted changes in climate due to climate change.

C. **Existing Resources:** The load-serving entity shall describe all existing resources that serve or meet the entity's customer's energy and capacity requirements. The IRP shall include the following, which may include references to data reported under Section R14-2-704 above:

1. A description of all demand-side resources currently being implemented by or on behalf of the load-serving entity.
2. A description of the energy supply from existing supply-side resources.
   a. This section shall describe each type of supply-side resources, and including at least the following categories:
      1. Utility-owned generation;
      2. Wholesale power purchase transactions that are one (1) year or longer and a detailed discussion of the transaction, including the term of the contract, expiration date, pricing provisions, source of the power, fuel source, and other relevant information;
      3. Cogeneration and small power production;
      4. Distributed generation;
      5. Pooling or coordination agreements that reduce resource requirements; and
      6. Any other supply-side resources.
   b. In addition, the following information concerning each existing supply-side resource shall be supplied, as applicable and as readily available to the load-serving entity with respect to third-party resources, in the form of a coherent table(s) in the body of the IRP:
      1. Resource type;
      2. Nameplate and peak available capacity;
      3. Annual capacity factor for each of the last five (5) years;
      4. Fuel type;
      5. Ownership information, including the portion of the resource owned by the load-serving entity, by a private project developer, or by a customer;
      6. Location (district or municipality);
      7. Commercial operation date;
      8. Remaining service life;
      9. Any anticipated projects or programs that would alter remaining service life;
      10. Remaining contract life, including capacity contracts;
      11. Depreciation schedule;
      12. Other contracts that need to be renegotiated (e.g., for water, land lease, fuel supply);
      13. Average annual heat rate over the last five (5) years;
      14. Current fuel cost in dollars per MMBtu;
      15. Current variable operations and maintenance (O&M) cost in dollars per MWh;
      16. Current total production cost in dollars per MWh, including any other necessary variables aside from fuel and variable O&M costs;
      17. Anticipated total production cost in dollars per MWh, including any other necessary variables aside from fuel and variable O&M costs, for future years through the planning period;
      18. Current fixed O&M cost in dollars per kW;
      19. Average annual capital expenditures over the last five (5) years in total dollars; and
      20. Average annual water consumption, source of supplied water.
   c. This section shall also include an assessment of potential cost-effective retirements of all utility-owned resources including the costs associated with incremental depreciation expenses and estimated operational and capital savings.
      1. For each retirement reviewed, the load-serving entity shall:
         i. Describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts; and
         ii. Evaluate at least one retirement date that is within the resource acquisition period.
      2. If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected, the load-serving entity shall provide:
         i. Identification of each power source or generating unit involved;
         ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating;
         iii. The reasons for each discontinuation, decommissioning, mothballing, or derating.

3. For the purpose of identifying existing resources that potentially are not cost-effective as compared to other resources available in the market, the load-serving entity shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of generic resources, including energy efficiency and demand response alternatives. The load-serving entity shall also conduct computer modeling that, at a minimum, evaluates retirement of each existing generating unit, and retirement of combinations of existing generating units, under a reasonable range of scenarios during the resource acquisition period. The load-serving entity need not model retirement of an existing generating unit if a screening analysis shows the unit to be clearly economic compared to replacement resources.

d. The following information concerning each existing supply-side resource shall be supplied as part of Appendix 5:

1. All information in sub-section (b) above;
2. Dates for renewal of operating licenses and permits, to the extent applicable;
3. Compliance schedule with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;
4. Expected capital and operating costs for compliance with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;
5. Expected yearly non-environmental capital expenditures for the first ten (10) years of the Planning Period, including any improvements to operational efficiencies or extensions of the useful life;
6. Any important changes to the resources that occurred since the acknowledgment of the most recent IRP or which is expected to occur prior to the filing of a review, update, or amendment, including:
   i. A description of each large capital project (over \$5,000,000) expected in the next five (5) years;
   ii. Changes in fuel types expected to result from economic restrictions or environmental regulations.

D. Resource Needs Assessment: The load-serving entity shall prepare a resource needs assessment and a detailed description of the results of such assessment. The purpose of the resource needs assessment is to identify current and/or future expected capacity and/or energy requirements resulting from the expected or contractual retirement of, or cessation of services from, existing supply and demand-side resources when compared against forecast load conditions. The resource needs assessment shall contain at least the following elements:

1. An expected planning reserve margin over a fifteen-year period.
   a. The planning reserve margin shall follow industry standard methodologies in assessing a necessary planning reserve margin to maintain reliable service during the planning period.
   b. To the extent that the reserve margin assessment cannot be developed independently of a resource plan, the load-serving entity may use its then-current business plan to assess and describe the necessary planning reserve margin.
   c. The load-serving entity shall demonstrate why the planning reserve margin targets in its forecast are reasonable.
2. A coherent table showing, by year, the expected capacity of each existing supply-side and existing demand-side resource, its load requirements, and load requirements including the planning reserve margin. The load-serving entity shall identify its annual net position relative to its expected needs throughout the planning period.
   a. The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period; and
   b. An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

E. New Source Options: The load-serving entity shall assess the need for its existing resources and any need to acquire new resource options that may reasonably serve or meet the load-serving entity's customer's energy and/or capacity requirements.

1. The IRP shall identify and evaluate a wide range of new supply-side resource options, including renewable and non-renewable options, to be used in the development of the IRP. While a load-serving entity may designate specific options as not feasible for future development, such designations must be accompanied by a clear and comprehensive explanation that justifies the load-serving entity's determination on the basis of cost, resource availability, or engineering feasibility.
   a. For each supply-side resource option identified as a feasible alternative, the load-serving entity shall provide the following information, as applicable, in the form of a coherent table in the body of the IRP:
      1. Resource type;
      2. Location, if a specific project site has been identified; otherwise, restrictions and other considerations that may dictate resource placement;
      3. Capacity;
      4. Fuel type;
      5. Capacity factor for renewable energy resources;
      6. Effective load carrying capacity (ELCC) or capacity contribution to peak;
      7. Ownership information, including the portion of the resource owned by the load-serving entity, by a private project developer, or by a customer;
      8. Anticipated service life;
      9. Heat rate;
      10. Overnight capital cost;
      11. Fixed operations and maintenance cost;
      12. Non-fuel variable operations and maintenance cost; and

13. Average annual water consumption.

b. For each resource identified in subsection (a) above, the following additional information shall be supplied:

1. All information in (a) above.
2. Other costs to construct and/or operate the resource, including financing costs, property taxes, supplemental payments, and interconnection costs;
3. Lead time necessary to plan and build, or acquire through a power purchase agreement;
4. Any constraints on the acquisition or construction of the resource as applied by the load-serving utility in the capacity expansion model, including first potential date of construction, maximum units feasible to acquire or construct per year, and total number of the resources allowed in the model through the planning period;
5. Any constraints on the operation or dispatch of the resource as applied by the load-serving entity in its modeling, including minimum up-time, minimum down-time, or energy or effluent limitations;
6. Any impact of the location of the resource on reliability and system resilience;
7. Evaluation of the interconnection of renewable energy projects and independent power producers to the utility system; and
8. A description, with quantitative information and analysis as required, of how the resource contributes to meeting the requirements of the Clean and Renewable Energy Standard in Article 18 of this Chapter.

2. The IRP shall include a projection and account for expected types and amounts of customer-owned distributed generation, by customer class, including:

a. A 15-year forecast of self generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);

b. Disaggregation of the forecast of subsection (B) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures;

c. A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified; and

d. Documentation of the analysis of the self generation;

3. This section shall also include the following:

a. A calculation of the benefits of generation using renewable energy resources;

b. Analysis of integration costs for intermittent resources;

c. A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;

d. A description of a wide range of potential new energy efficiency and demand response programs.

1. For each demand management program or measure, the IRP will describe:
   i. How and when the program or measure will be implemented;
   ii. The projected participation level by customer class for the program or measure;
   iii. The expected change in peak demand and energy consumption resulting from the program or measure;
   iv. The expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure;
   v. The expected societal benefits, societal costs, and cost-effectiveness of the program or measure;
   vi. The expected life of the measure; and
   vii. The capital costs, operating costs, and maintenance costs of the measure, and the program costs;
2. For each demand management measure that was considered but rejected:
   i. A description of the measure;
   ii. The estimated change in peak demand and energy consumption from the measure;
   iii. The estimated cost-effectiveness of the measure;
   iv. The capital costs, operating costs, and maintenance costs of the measure, and the program costs; and
   v. The reasons for rejecting the measure.

e. A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

F. Assumptions and Forecasts

1. The IRP shall document key modeling assumptions and inputs including, at least, the following:

a. Annual fuel prices for each delivered fuel;

b. Annual emission prices;

c. Economic conditions;

d. Environmental regulations;

e. Other non-environmental regulations, including renewable portfolio standards;

f. Utility discount rate or weighted average cost of capital;

g. Annual debt limitations.

2. The IRP shall also identify factors that will significantly influence key forecasts (including electricity demand, electricity consumption, fuel prices), and develop a range of possible outcomes for those forecasts encompassing at least the fifth (5th) and ninety-fifth (95th) percentile outcomes as understood by the load-serving entity.

a. Forecasts should include exogenous elements beyond the load-serving entity's control, including but not limited to:

1. Economic conditions;

2. Environmental regulations;
3. Changes in customer load not caused by utility demand-side resources;
4. Customer-sited distributed generation;
5. Fuel prices;
6. Emissions costs; and
7. Capital costs.

b. For each forecast, the IRP shall identify a reference case forecast, and describe the basis of the forecast range identified.

c. The IRP shall consider multiple scenarios that encompass the reasonable range of possible outcomes for uncertain forecasts. Scenarios may combine key forecasts in a manner that enables a reasonable exploration of the range of foreseeable risks to the safety, reliability, and affordability of retail services. The IRP shall consider a sufficient number of scenarios to both describe feasible or likely sets of forecasts, as well as capture a wide range of possible risks.
1. The load-serving utility shall justify the scenarios used and excluded from consideration and describe why the combinations assessed represent a reasonable range of risks.
2. To the extent that the load-serving entity relies on explicit or implicit relationships or correlations between forecasts, the load-serving entity shall describe the basis of the relationships.
3. The load-serving entity shall incorporate any scenarios required by the Commission or reasonably suggested by interested stakeholders.

d. The IRP shall include a Reference Case Scenario, representing the load-serving entity's best understanding of expected circumstances or median probability outcomes.

C. Resource Plan Development.

1. The IRP shall identify in detail the mechanisms used by the load-serving entity in developing its resource plans.
a. The IRP shall include, within the main body of the IRP, the following:
1. Comprehensive descriptions of the modeling mechanisms used in the development and sensitivity analysis of each resource plan, based on Capacity Expansion Models. The load-serving entity may in addition use production cost models, a heuristic approach, or a combination of the two.
2. Descriptions of key resource plan assumptions and purposes, including consideration of stakeholder input and Commission requirements;
3. A coherent table illustrating the key difference between resource plans, including annual retirements, retrofits or conversions, and new builds for both supply- and demand-side resources, changes in capacity (uprates or derations) or existing supply- and demand-side resources, changes in transmission or distribution systems, key assumptions, and resource plan cost;
4. A description of the mechanism and criteria used to select the Preferred Resource Plan, following the requirements of subsection (2)(c) below;
5. A coherent load and resource balance table for the Preferred Resource Plan showing, by year, the expected capacity of each existing and new supply-side and demand-side resource, its expected peak load, its planning reserve margin, and its total load requirements, including the planning reserve margin. The load-serving entity shall identify its annual net position relative to its expected needs during the planning period.
6. For the Preferred Resource Plan, and for each resource plan considered in the IRP, the IRP shall include, at a minimum, the following supplemental information:
i. A table of annual capacity contribution by resource;
ii. A table of annual generation by resource;
iii. A table of annual emissions by resource;
iv. A table of annual fuel consumption by fuel type;
v. A cash-flow table comprised of annual cost values for, at a minimum, fuel spending by type of fuel, generation capital, transmission capital, fuel infrastructure capital, total generating unit variable operations and maintenance, total generating unit fixed operations and maintenance, fuel infrastructure operations and maintenance, CO2, NOx, SO2 emissions, water consumption, fossil fuel power purchase agreements; and renewable power purchase agreements.

2. Resource Plan Development Analysis
a. The IRP shall use a Capacity Expansion Model to develop least-cost resource plans that meet customer needs under the reference case scenario and various future scenarios. If the load-serving entity does not use a Capacity Expansion Model to develop least-cost resource plans, the load-serving entity must seek, and receive, a waiver from the Commission to use any other kind of resource plan development model for this purpose, in which case the Commission may adopt through resolution any and all appropriate requirements to ensure reliability of the information and conclusions produced and presented in the IRP.
1. The Capacity Expansion Model shall, at a minimum:
i. Seek to optimize the present value of revenue requirements over the planning period;
ii. Consider demand-side resources in a competitive framework with supply-side resources;
iii. Recognize all utility-borne costs associated with the development of new resources;
iv. Recognize all utility-borne costs, as well as avoided costs, associated with the retirement or modification of existing resources.
2. Costs that the load-serving entity has incurred or committed prior to the commencement of the planning period (including, but not limited to, existing plant balances, committed capital expenditures, and rate-based costs) shall not

be assessed in the Capacity Expansion Model unless they are specifically avoidable through the procurement of new assets or retirement or modification of existing assets.

3. The load-serving entity shall use the Capacity Expansion Model to develop a comprehensive set of resource plans to include a wide variety of supply-side, energy efficiency, and demand response resources.
4. Supply-side resources shall include various options for early retirement of existing power plants, for refurbishment or repowering of existing power plants, and for deferral of new power plants where feasible.
5. Supply-side resources shall also include any changes in the transmission or distribution systems that accompany generation resources or are necessary for the maintenance of system reliability.
6. Energy efficiency and demand response resources shall include programs with a variety of different cost levels, in order to assist in the identification of all cost-effective energy and demand respond resources.
7. The load-serving entity shall incorporate any resource plans required by the Commission.
8. The load-serving entity shall provide a comprehensive discussion of any resource plans excluded from consideration on the basis of reliability or viability.
9. Each resource plan shall be designed to ensure that the load-serving entity complies with the Clean and Renewable Energy Standard requirements of Article 18 of this Chapter.

b. Each of the resource plans resulting from the Resource Plan Development Modeling shall be subjected to sensitivity analyses exploring a reasonable range of uncertainty in forecast assumptions. The purpose is to examine the robustness of resource plans created in the optimization analysis (i.e., how each plan affected by changes in the input assumptions). To that end, the IRP shall include a compilation of the following analyses and plans:
   1. Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:
      i. Demand forecasts;
      ii. The costs of demand management measures and power supply;
      iii. The availability of sources of power;
      iv. The costs of compliance with existing and expected environmental regulations;
      v. Any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations;
      vi. Changes in fuel prices and availability;
      vii. Construction costs, capital costs, and operating costs; and
      viii. Other factors the load-serving entity wishes to consider;
   2. A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (b)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects; and
   3. A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (b)(1).

c. The load-serving entity shall select a Preferred Resource Plan from among the resource plans developed and evaluated in the optimization and sensitivity analyses.
   1. In selecting the Preferred Resource Plan, the load-serving entity shall use the minimization of the present value of revenue requirements as the primary selection criterion.
   2. The load-serving entity shall also consider other criteria, including but not limited to, system reliability; short- and long-term risk; environmental impacts; transmission needs and implications; distribution needs and implications; financial impacts on the load-serving entities; opportunities to site renewable facilities in communities where conventional generation has been retired; and the public interest. Where meeting these needs is associated with quantifiable costs, these costs shall be included in the calculation of the present value of revenue requirements.
   3. The IRP shall include detailed discussion of each of the above factors in support of its Preferred Resource Plan. The load-serving entity may opt to choose a plan that is not the lowest cost, provided that, in doing so, it presents a detailed description of all the criteria and reasoning used to select the Preferred Resource Plan that is not the lowest cost.

H. Caveats and Limitations: The IRP shall include an annotated list of key caveats and limitations of its analysis, including the impact of uncertainty, the modeling mechanism, key regulatory and project execution assumptions, and costs. The purpose of this section is to illustrate the load-serving entity's certainty with respect to the Preferred Resource Plan.

I. Work Plan: No more than two (2) years following a load-serving entity's most recently-submitted IRP, the load-serving entity shall file with Docket Control a work plan that includes:
1. An outline of the contents of the IRP the load-serving entity is developing to be filed the following year as required under Section R14-2-705(B);
2. The load-serving entity's method for assessing potential resources;
3. The sources of the load-serving entity's current assumptions and a plan to incorporate forecasts based on inputs suggested by stakeholders; and

4. An outline of how the load-serving entity plans to ensure significant stakeholder engagement, including the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan.
   a. The load-serving entity must provide for at least four meetings with stakeholders during the IRP development process for the following purposes:
      1. At the beginning, to collaborate on the planning approach, priorities, and evaluation criteria;
      2. Prior to extensive analysis, to discuss model input assumptions and analysis structure;
      3. Post-analysis, to discuss the results and draw conclusions about the import of those results; and
      4. After a final draft IRP has been developed, to present findings and the resulting actions before it is filed with ACC.
   b. The load-serving entity may provide additional meetings depending on the level of interest from stakeholders.
   c. In order to make these meetings effective, stakeholders must have access to the pertinent data, including modeling inputs and assumptions, if necessary under a reasonable non-disclosure agreement or protective order that effectively balances the public's right to access information with the utility's interest in limiting access to confidential business information, and the utilities should be prepared with the appropriate personnel and experts to answer questions. Throughout the stakeholder engagement process, the load-serving entity must, at a minimum:
      1. Solicit alternative modeling inputs/parameters for alternative modeling runs; and
      2. Respond to requested alternatives by either performing the runs or explaining why they chose not to perform the requested runs.
   d. Following each meeting, the load-serving entity shall provide meetings minutes, or if possible a recording, for future reference by stakeholders and to ensure that the utility has future access to all relevant information or concerns raised during the meetings. Such minutes or recording must provide enough information to make clear who (either which individual or organization) presented any given idea or suggestion during a meeting.
   e. The work plan shall describe and demonstrate that the stakeholder engagement process has been satisfied and will continue to be met throughout the IRP process;

J. **Action Plan:** With its IRP, a load-serving entity shall include an action plan, based on the results of the resource planning process.
1. The purpose of the action plan is to specify implementation actions that need to be performed during the first five years of the planning period as a result of the Preferred Resource Plan. The action plan is not intended to replace or modify additional resource certification processes required by statute or other Commission rules and orders.
2. The action plan shall include, at a minimum:
   a. Details on the intent and specific markers required to meet the load-serving entity's specific needs over the first five years of the planning period.
      1. The action plan shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral.
      2. The purpose of the action plan is to facilitate in a subsequent all-source RFP consideration of demand-side resources on equal footing as supply-side ones and must not be limited to "dispatchable" resources.
   b. A summary of actions on treatment of existing resources or future resource acquisitions that the load-serving entity believes may satisfy its defined future needs based on the Preferred Resource Plan. This should include a table of key actions in the first five years after acknowledgment of the IRP including, at a minimum, expected procurement processes for supply-side resources and energy efficiency, permitting requirements, construction activities, required studies, and other significant events. Although such summary and table shall provide the load-serving entity's suggestions for specific actions, the load-serving entity shall base its selection of specific resources on the results of an all-source RFP to satisfy the needs identified in subsection (a) above.
      1. The action plan shall cover intended acquisitions of demand-side, supply-side, transmission, distribution, and/or fuel infrastructure resources; retirements and/or retrofits of existing generating resources; entrance into, renegotiation or cessation of power purchase agreements; and any other resource commitments.
      2. For each action identified in the action plan, the IRP shall specify and provide:
         i. The expected calendar year and quarter in which the action will be commenced;
         ii. The expected calendar year and quarter in which the action will be completed;
         iii. Issuances of permits and other regulatory actions that are required in order for the action to take place;
         iv. For any major expected resource acquisitions, retirements, retrofits, or power purchase agreements, the action plan shall provide information on the cost of the option chosen and the plan for financing that option;
         v. The anticipated impact of the action on any relevant performance metrics established by the Commission; and
         vi. Any other information required by the Commission through resolution or order.
3. The action plan shall cover the five-year period following the Commission's acknowledgment of the resource plan. Any given action plan will remain in effect until a new action plan is approved as part of a subsequent IRP proceeding or until the Commission states otherwise.
4. The IRP shall provide a status update on the implementation of the action plan in effect at the time of the filing of the IRP (or the most recent action plan, if the filing of a proposed IRP occurs after the expiration of any previous action plan). This status update shall include the following:
   a. An itemized list of each element of the prior IRP action plan;
   b. A description of the load-serving entity's actions taken to execute each action item;

c. Any changes to date in the timeframe of expected commencement and completion, permitting or regulatory requirements, or removal of the action item based on intervening events;
d. Any changes to permitting, engineering, or construction processes of major projects already in progress; and
e. A description of the cause of any changes to the prior IRP action plan.

5. The action plan shall also provide an explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided costs shall include, but is not limited to, the following:
   a. The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement;
   b. The avoided transmission capacity cost;
   c. The avoided distribution capacity cost; and
   d. The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.

R14-2-70~~4~~7. Commission Review and Acknowledgement of Load-serving Entity Integrated Resource Plans

A. IRP Prefiling Process~~By October 1 of each even year, Staff shall file a report that contains its analysis and conclusions regarding its statewide review and assessments of the load-serving entities' filings made under R14-2-703(C), (D), (E), (F), and (H).~~

1. At least one year before the next IRP is due, the Commission may schedule one or more technical conferences to gather information regarding the methodology and contents contemplated by the load-serving entity for its new IRP proposal.
   a. In scheduling these technical conferences, the Commission may require a load-serving entity to provide specific information regarding the development of the proposed IRP.
   b. The Commission will set forth, in its orders scheduling the technical conferences, the process for the orderly presentation of the information.
   c. The purpose of these technical conferences is to provide an opportunity for the Commission to ensure a load-serving entity's IRP filing will reasonably comply with the requirements set forth in this Regulation and the analysis conducted therein will be sufficiently robust so as to comply with public policy goals and meet Commission expectations as to the quality of the analysis and information provided. These proceedings will also provide an opportunity for the load-serving entity to seek clarifications from the Commission with regards to compliance with the requirements set forth in this Regulation.
   d. The Commission may require a load-serving entity to address any issues it believes should be included in the IRP that are not specifically set forth in these rules.
2. The load-serving entity shall, before setting assumptions on cost of particular resources, conduct an all-source Request for Information (RFI), wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants.
   a. The resulting bids shall form a cohort of known new resource options with appropriate pricing and availability that shall be used to inform assumptions and the evaluation of resources within the IRP.
   ~~a.~~b. The RFI shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFI shall consider demand-side resources one equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

B. Review by Staff ~~By February 1 of each odd year, the Commission shall issue an order acknowledging a load-serving entity's resource plan or issue an order stating the reasons for not acknowledging the resource plan. The Commission shall order an acknowledgment of a load-serving entity's resource plan, with or without amendment, if the Commission determines that the resource plan, as amended if applicable, complies with the requirements of this Article and that the load-serving entity's resource plan is reasonable and in the public interest, based on the information available to the Commission at the time and considering the following factors:~~

~~1. The total cost of electric energy services;~~
~~2. The degree to which the factors that affect demand, including demand management, have been taken into account;~~
~~3. The degree to which supply alternatives, such as self generation, have been taken into account;~~
~~4. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the load-serving entity to respond to unforeseen changes in supply and demand factors;~~
~~5. The reliability of power supplies, including fuel diversity and non-cost considerations;~~
~~6. The reliability of the transmission grid;~~
~~7. The environmental impacts of resource choices and alternatives;~~
~~8. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;~~
~~9. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers;~~
~~10. The best combination of expected costs and associated risks for the load-serving entity and its customers; and~~
~~11. The degree to which the load-serving entity's resource plan allows for coordinated efforts with other load-serving entities.~~

1. Within three (3) months of the submission of a preliminary IRP, Staff shall file a report that contains its analysis and conclusions regarding its statewide review and assessments of the load-serving entity's IRP.
2. If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff shall request additional information from the load-serving entity, including the data used in the load-serving entity's analyses.

3. Staff may request that a load-serving entity complete additional analyses to improve specified components of the load-serving entity's submissions and may request a technical conference with the load-serving in order to gather information regarding the methodology and contents contemplated by the utility so that the Commission can assess the quality and robustness of the utility's analysis.

C. Review by Commission: ~~The Commission may hold a hearing or workshop regarding a load-serving entity's resource plan. If the Commission holds such a hearing or workshop, the Commission may extend the February 1 deadline for the Commission to issue an order regarding acknowledgment under subsection (H).~~ Within 9 months of the filing of a preliminary IRP, the Commission shall issue an order making the following specific findings:

1. **Completion:** The Commission shall determine whether the IRP is adequate as an informational document to allow full and robust review by stakeholders and the ACC and to facilitate consideration of the load-serving entity's resource alternatives. If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff or the Commission shall request additional information from the load-serving entity, including the data used in the load-serving entity's analyses. A determination of completeness or sufficiency as an informational document shall not be construed as a ruling on the substance of the IRP.
2. **Acknowledgement:** The Commission shall issue an order acknowledging, rejecting, or modifying a load-serving entity's IRP in whole or in part. The Commission will acknowledge components of the IRP if the Commission determines that the IRP, as amended if applicable, complies with the requirements of this Article and that the load-serving entity's IRP is reasonable and in the public interest, based on the information available to the Commission at the time and considering the following factors:
   a. The IRP sufficiently analyzed the components provided under Section R14-2-706;
   b. The total cost of electric energy services (the IRP should provide least-cost service);
   c. The degree to which the factors that affect demand, including demand management, have been taken into account;
   d. The degree to which the IRP will minimize, to the extent practicable, adverse socioeconomic and environmental effects;
   e. The degree to which the IRP will enhance the utility's ability to respond to financial, social, and technological changes affecting its operations;
   f. The degree to which supply alternatives, such as self generation, have been taken into account;
   g. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the load-serving entity to respond to unforeseen changes in supply and demand factors;
   h. The reliability of power supplies, including fuel diversity and non-cost considerations;
   i. The reliability of the transmission grid;
   j. The degree to which the IRP will limit the risk of adverse effects on the utility and its customers from factors outside of the utility's control;
   k. The environmental impacts of resource choices and alternatives;
   l. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;
   m. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers; and
   n. The degree to which the load-serving entity's IRP allows for coordinated efforts with other load-serving entities.
3. A load-serving entity may seek Commission approval of specific resource planning actions.

D. Procedure Before the Commission ~~While no particular future ratemaking treatment is implied by or shall be inferred from the Commission's acknowledgment, the Commission shall consider a load-serving entity's filings made under R14-2-703 when the Commission evaluates the performance of the load-serving entity in subsequent rate cases and other proceedings.~~

1. **Hearing:** The Commission may hold a hearing or workshop regarding a load-serving entity's IRP. If the Commission holds such a hearing or workshop, the Commission may extend the deadline for the Commission to issue an order regarding acknowledgment under subsection (C). Any public hearing shall be on the record and a transcript shall be made publicly available for future reference by stakeholders and the load-serving entity.
2. **Discovery:** The Commission shall permit reasonable discovery by interested stakeholders during the prefiling process, after an IRP is filed, and during the hearing in order to assist parties and interested persons in obtaining evidence concerning the integrated resource plan, including, but not limited to, the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties. Data protected by a protective order shall not be submitted to Docket Control and will not be open to public inspection or otherwise made public except upon an order of the Commission entered after written notice to the load-serving entity. Interested stakeholders shall have the opportunity to agree to reasonable terms of a protective order in order to gain access to protected information.
3. **Confidentiality and Protective Orders:** If a load-serving entity believes that a data-reporting requirement may result in disclosure of confidential business data or confidential electricity infrastructure information, the load-serving entity may submit to Staff a request that the data be submitted to Staff under a protective order, which request shall include an explanation justifying the confidential treatment of the data.
4. **Supplemental Information:** A load-serving entity or interested party may provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops. Similarly, if comments from interested stakeholders indicate additional information is appropriate, Staff or the Commission may request such information from the load-serving entity.
5. **Effect of Commission Acknowledgment:** While no particular future ratemaking treatment is implied by or shall be inferred from the Commission's acknowledgment, the Commission shall consider a load-serving entity's filings made under R14-2-706 when the Commission evaluates the performance of the load-serving entity in subsequent rate cases and other proceedings. Although decisions

regarding whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate case proceeding, acknowledgment of an IRP is relevant to subsequent examination of whether a utility s resource investment is prudent and should be recovered from ratepayers. Just as acknowledgement does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of impudence. The Commission can nevertheless consider whether a load-serving entity has proceeded with an expenditure that has either been expressly rejected or otherwise not acknowledged by the Commission when evaluating the performance of the load-serving entity in a subsequent rate case.

~~E. A load-serving entity may seek Commission approval of specific resource planning actions.~~

~~F. A load-serving entity may file an amendment to an acknowledged resource plan if changes in conditions or assumptions necessitate a material change in the load-serving entity's plan before the next resource plan is due to be filed.~~

R14-2-708. Update, Amendment, or Review to an Acknowledged IRP

A load-serving entity may file an amendment to an acknowledged IRP if changes in conditions or assumptions necessitate a material change in the load-serving entity's plan before the next IRP is due to be filed. As soon as the load-serving entity anticipates a significant deviation from its acknowledged IRP, it must file an update / amendment with the Commission unless the load-serving entity is within six months of filing its next IRP. This filing must meet the requirements set forth in Section R14-2-706 of this rule.

A. Reasons that might warrant a load-serving entity to consider proposing an update / amendment include, but are not limited to:
   1. It anticipates submitting an application for a certificate to construct, purchase, or otherwise acquire a long-term supply-side or demand-side resource that was not previously included as part of the current acknowledged IRP;
   2. It anticipates the need to undertake a procurement process for a demand-side or supply-side resource that was not included as part of the current acknowledged IRP;
   3. It expects to make a Major Change to the IRP or the Action Plan before the filing of the next IRP proposal.

B. Notwithstanding paragraph (A), the Commission shall have the authority to require a load-serving entity to file an update, amendment, or review to the acknowledged IRP, should it determine that conditions warrant such action.

C. If the load-serving entity requests Commission acknowledgement of proposed changes to the action plan contained in its acknowledged IRP:
   1. The load-serving entity must file its proposed changes with the Commission and present the results of its proposed changes to the Commission at a public meeting prior to the deadline for written public comment; and
   2. Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the load-serving entity's filing of its request for acknowledgement of proposed changes; and
   3. The Commission may provide direction to an energy utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

D. The filing of an IRP update does not relieve a load-serving entity from its obligation to file a new, complete IRP every three (3) years.

R14-2-70~~9~~5. Procurement

A. Except as provided in subsection (B), a load-serving entity may use the following procurement methods for the wholesale acquisition of energy, capacity, and physical power hedge transactions:
   1. Purchase through a third-party online trading system;
   2. Purchase from a third-party independent energy broker;
   3. Purchase from a non-affiliated entity through auction or an RFP process;
   4. Bilateral contract with a non-affiliated entity;
   5. Bilateral contract with an affiliated entity, provided that non-affiliated entities were provided notice and an opportunity to compete against the affiliated entity's proposal before the transaction was executed; and
   6. Any other competitive procurement process approved by the Commission.

B. Any RFP shall seek to satisfy a load-serving entity's basic needs, as defined in the action plan, rather than define a specific technology or source. As such, an RFP shall be technology neutral, location neutral (any unit that can deliver energy/capacity into the particular zone even if not located there should be permitted to compete), except that preference shall be given to renewable resources sited in communities where conventional generation has been retired, and size neutral. The RFP shall consider demand-side resources one equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

~~B~~C. A load-serving entity shall use an RFP process as its primary acquisition process for the wholesale acquisition of energy and capacity, unless one of the following exceptions applies:
   1. The load-serving entity is experiencing an emergency;
   2. The load-serving entity needs to make a short-term acquisition to maintain system reliability;
   3. The load-serving entity needs to acquire other components of energy procurement, such as fuel, fuel transportation, and transmission projects;
   4. The load-serving entity's planning horizon is two years or less;
   5. The transaction presents the load-serving entity a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, compared to the cost of acquiring new generating facilities, and will provide unique value to the load-serving entity's customers;
   6. The transaction is necessary for the load-serving entity to satisfy an obligation under the Renewable Energy Standard rules; or
   7. The transaction is necessary for the load-serving entity's demand-side management or demand response programs.

~~C~~D. A load-serving entity shall engage an independent monitor to oversee all RFP processes for procurement of new resources.

R14-2-70~~6~~10. Independent Monitor Selection and Responsibilities

A. When a load-serving entity contemplates engaging in an RFP process, the load-serving entity shall consult with Staff regarding the identity of companies or consultants that could serve as independent monitor for the RFP process.

B. After consulting with Staff, a load-serving entity shall create a vendor list of three to five candidates to serve as independent monitor and shall file the vendor list with Docket Control to allow interested persons time to review and file objections to the vendor list.

C. An interested person shall file with Docket Control, within 30 days after a vendor list is filed with Docket Control, any objection that the interested person may have to a candidate's inclusion on a vendor list.

D. Within 60 days after a vendor list is filed with Docket Control, Staff shall issue a notice identifying each candidate on the vendor list that Staff has determined to be qualified to serve as independent monitor for the contemplated RFP process. In making its determination, Staff shall consider the experience of the candidates, the professional reputation of the candidates, and any objections filed by interested persons.

E. A load-serving entity that has completed the actions required by subsections (A) and (B) to comply with a particular Commission Decision is deemed to have complied with subsections (A) and (B) and is not required to repeat those actions.

F. A load-serving entity may retain as independent monitor for the contemplated RFP process and for its future RFP processes any of the candidates identified in Staff's notice.

G. A load-serving entity shall file with Docket Control a written notice of its retention of an independent monitor.

H. A load-serving entity is responsible for paying the independent monitor for its services and may charge a reasonable bidder's fee to each bidder in the RFP process to help offset the cost of the independent monitor's services. A load-serving entity may request recovery of the cost of the independent monitor's services, to the extent that the cost is not offset by bidder's fees, in a subsequent rate case. The Commission shall use its discretion in determining whether to allow the cost to be recovered through customer rates.

I. One week prior to the deadline for submitting bids, a load-serving entity shall provide the independent monitor a copy of any bid proposal prepared by the load-serving entity or entity affiliated with the load-serving entity and of any benchmark or reference cost the load-serving entity has developed for use in evaluating bids. The independent monitor shall take steps to secure the load-serving entity's bid proposal and any benchmark or reference cost so that they are inaccessible to any bidder, the load-serving entity, and any entity affiliated with the load-serving entity.

J. The independent monitor and load-serving entity must provide an opportunity for public review of a summary of each project proposal and for public comment on proposed bid ranking.

K~~J~~. Upon Staff's request, the independent monitor shall provide status reports to Staff throughout the RFP process.

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 18. CLEAN AND RENEWABLE ENERGY STANDARD ~~AND TARIFF~~

Section

R14-2-1801. Definitions

1~~A~~. "Affected Utility" means a public service corporation serving retail electric load in Arizona, but excluding any Utility Distribution Company with more than half of its customers located outside of Arizona.

2~~B~~. "Annual Renewable Energy Requirement" means the portion of an Affected Utility's annual retail electricity sales that must come from Eligible Renewable Energy Resources.

3. "Arizona Dedicated Generation" means the energy produced from Dedicated Generation, adjusted as follows:
   a. If that generation produces more energy in a year than the Affected Utility's Arizona load, then Arizona Dedicated Generation is the sum of all renewable energy from Dedicated Generation, plus the energy from the remaining Dedicated Generation proportionately reduced by multiplying the energy produced from each generator times the ratio of 1) the Arizona load reduced by the energy produced by the renewable energy Dedicated Generation, to 2) the total megawatt-hours produced from the remaining (non-renewable) Dedicated Generation.
   b. If that generation produces less energy in a year than the Affected Utility's Arizona Load, power purchases by the Affected Utility that are not Dedicated Generation, but are needed to meet the Affected Utility's Arizona Load during the applicable calendar year, shall be considered Dedicated Generation with an emission rate equal to the Unspecified Power Rate.

4. "Arizona Load" means the megawatt-hours of electricity during a year that an Affected Utility sells to its Arizona retail customers, plus line losses, minus load that has Renewable Energy Resources dedicated to serve a particular customer, provided that the particular customer retains the Renewable Energy Credits or the Renewable Energy Credits are retired on their behalf by the Affected Utility as a part of a voluntary program, product, or sales, and are not used for compliance with any law or regulation in any jurisdiction.

5. "Base period emissions" means the average annual metric tons of carbon-dioxide that the Affected Utility emitted into the atmosphere from its Arizona Dedicated Generation during a consecutive three-calendar-year period of 2016 to 2018.

6. "Clean Energy Credit," or "CEC" means an instrument, in a physical or electronic format approved by the Commission that represents, for every gigawatt-hour produced by Arizona Dedicated Generation in a year, each metric ton of carbon-dioxide emissions less than one thousand. For any electric generating facility that is awarded Renewable Energy Credits associated with its electricity production, emissions of less than one-thousand metric tons per gigawatt-hour will only be recognized in the base period emissions determination, and in the award of Clean Energy Credits during a compliance period, if the Renewable Energy Credit associated with that production has been or will be retired by the Affected Utility, and has not and

will not be retired for voluntary renewable energy sales or programs. The emission rate for energy from Renewable Energy Resources without Renewable Energy Credits that meet this requirement shall equal the applicable Unspecified Power Emission Rate.

7. "Clean Energy Resource" means an energy resource that operates with zero net Emissions.

8. "Commission" means the Arizona Corporation Commission.

9. "Community Distributed Generation" means a renewable generation facility that is located in the service territory of an Affected Utility where the beneficial use of the electricity generated by the facility is attributed to the subscribers. There shall be at least ten subscribers and the facility shall have a capacity of no more than 10 MW. The owner of the community distributed generation facility may be the Affected Utility or any other for-profit or non-profit entity or organization, including a subscriber organization that contracts to sell the output from the community distributed generation facility to the Affected Utility.

10~~C~~."Conventional Energy Resource" means an energy resource that is non-renewable in nature, such as natural gas, coal, oil, and uranium, or electricity that is produced with energy resources that are not Renewable Energy Resources.

11~~D~~."Customer Self-Directed Renewable Energy Option" means a Commission-approved program under which an Eligible Customer may self-direct the use of its allocation of funds collected pursuant to an Affected Utility's Tariff.

12. "Dedicated Generation" means electric energy production capacity that is assigned to the Affected Utility for Arizona ratemaking purposes, and that is either owned by the Affected Utility or a corporate affiliate, or committed to the Affected Utility or a corporate affiliate pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes, less any such capacity sold by the Affected Utility pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes, and less any renewable energy capacity committed to a particular customer or a voluntary renewable energy purchase program.

13~~E~~."Distributed Generation" means electric generation sited at a customer premises, providing electric energy to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.

14~~F~~."Distributed Renewable Energy Requirement" means a portion of the retail kilowatt-hours sold by an Affected ~~Annual Renewable Energy Requirement~~ that must be met with production~~Renewable Energy Credits~~ derived from resources that qualify as Distributed Renewable Energy Resources pursuant to R14-2-180~~32~~(B).

15~~G~~. "Distributed Solar Electric Generator" means electric generation sited at a customer premises, providing electric energy from solar electric resources to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.

16~~H~~. "Eligible Customer" means an entity that pays Tariff funds of at least $25,000 annually for any number of related accounts or services within an Affected Utility's service area.

17. "Emissions" means carbon-dioxide (CO_2) emitted into the atmosphere.

~~I. "Extra Credit Multiplier" means a way to increase the Renewable Energy Credits attributable to specific Eligible Renewable Energy Resources in order to encourage specific renewable applications.~~

18. "Gigawatt-hour" means one thousand megawatt-hours or one million kilowatt-hours.

19~~J~~. "Green Pricing" means a rate option in which a customer elects to pay a tariffed rate premium for electricity derived from Eligible Renewable Energy Resources.

20~~K~~. "Market Cost of Comparable Conventional Generation" means the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.

21~~L~~."Net Billing" means a system of billing a customer who installs an Eligible Renewable Energy Resource generator on the customer's premises for retail electricity purchased at retail rates while crediting the customer's bill for any customer-generated electricity sold to the Affected Utility at avoided cost.

22~~M~~. "Net Metering" means a system of metering electricity by which the Affected Utility credits the customer at the full retail rate for each kilowatt-hour of electricity produced by an Eligible Renewable Energy Resource system installed on the customer-generator's side of the electric meter, up to the total amount of electricity used by that customer during an annualized period, and which compensates the customer-generator at the end of the annualized period for any excess credits at a rate equal to the Affected Utility's avoided cost of wholesale power. The Affected Utility does not charge the customer-generator any additional fees or charges or impose any equipment or other requirements unless the same is imposed on customers in the same rate class that the customer-generator would qualify for if the customer-generator did not have generation equipment.

23~~N~~."Renewable Energy Credit" means the unit created to track kWh derived from an Eligible Renewable Energy Resource or kWh equivalent of Conventional Energy Resources displaced by Distributed Renewable Energy Resources.

24~~O~~. "Renewable Energy Resource" means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.

Renewable Energy Resources and that are delivered to Arizona customers to meet the Annual Renewable Energy Requirements.

5. "Fuel Cells that Use Only Renewable Fuels" are fuel cell electricity generators that operate on renewable fuels, such as hydrogen created from water by Eligible Renewable Energy Resources. Hydrogen created from non-Renewable Energy Resources, such as natural gas or petroleum products, is not a renewable fuel.
6. "Geothermal Generator" is an electricity generator that uses heat from within the earth's surface to produce electricity.
7. "Hybrid Wind and Solar Electric Generator" is a system in which a Wind Generator and a solar electric generator are combined to provide electricity.
8. "Landfill Gas Generator" is an electricity generator that uses methane gas obtained from landfills to produce electricity.
9. "New Hydropower Generator of 10 MW or Less" is a generator, installed after January 1, 2006, that produces 10 MW or less and is either:
   a. A low-head, micro hydro run-of-the-river system that does not require any new damming of the flow of the stream; or
   b. An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or
   c. Generation using canals or other irrigation systems.
10. "Solar Electricity Resources" use sunlight to produce electricity by either photovoltaic devices or solar thermal electric resources.
11. "Wind Generator" is a mechanical device that is driven by wind to produce electricity.

B. "Distributed Renewable Energy Resources" are Community Distributed Generation as defined in section R14-2-1801(9) or applications of the following defined technologies that are located at a customer's premises and that displace Conventional Energy Resources that would otherwise be used to provide electricity to Arizona customers:

1. "Biogas Electricity Generator," "Biomass Electricity Generator," "Geothermal Generator," "Fuel Cells that Use Only Renewable Fuels," "New Hydropower Generator of 10 MW or Less," or "Solar Electricity Resources," as each of those terms is defined in subsections (A)(1), (A)(2), (A)(5), (A)(6), (A)(9), and (A)(10).
2. "Biomass Thermal Systems" and "Biogas Thermal Systems" are systems which use fuels as defined in subsections (A)(1) and (A)(2) to produce thermal energy and that comply with Environmental Protection Agency Certification Programs or are permitted by state, county, or local air quality authorities. For purposes of this definition "Biomass Thermal Systems" and "Biogas Thermal Systems" do not include biomass and wood stoves, furnaces, and fireplaces.
3. "Commercial Solar Pool Heaters" are devices that use solar energy to heat commercial or municipal swimming pools.
4. "Geothermal Space Heating and Process Heating Systems" are systems that use heat from within the earth's surface for space heating or for process heating.
5. "Renewable Combined Heat and Power System" is a Distributed Generation system, fueled by an Eligible Renewable Energy Resource, that produces both electricity and useful renewable process heat. Both the electricity and renewable process heat may be used to meet the Distributed Renewable Energy Requirement.
6. "Solar Daylighting" is the non-residential application of a device specifically designed to capture and redirect the visible portion of the solar beam, while controlling the infrared portion, for use in illuminating interior building spaces in lieu of artificial lighting.
7. "Solar Heating, Ventilation, and Air Conditioning" ("HVAC") is the combination of Solar Space Cooling and Solar Space Heating as part of one system.
8. "Solar Industrial Process Heating and Cooling" is the use of solar thermal energy for industrial or commercial manufacturing or processing applications.
9. "Solar Space Cooling" is a technology that uses solar thermal energy absent the generation of electricity to drive a refrigeration machine that provides for space cooling in a building.
10. "Solar Space Heating" is a method whereby a mechanical system is used to collect solar energy to provide space heating for buildings.
11. "Solar Water Heater" is a device that uses solar energy rather than electricity or fossil fuel to heat water for residential, commercial, or industrial purposes.
12. "Wind Generator of 1 MW or Less" is a mechanical device, with an output of 1 MW or less, that is driven by wind to produce electricity.

C. Except as provided in subsection (A)(4), Eligible Renewable Energy Resources shall not include facilities installed before January 1, 1997.

D. The Commission may adopt pilot programs in which additional technologies are established as Eligible Renewable Energy Resources or Distributed Renewable Energy Resources. Any such additional technologies shall be Renewable Energy Resources that produce electricity, replace electricity generated by Conventional Energy Resources, or replace the use of fossil fuels with Renewable Energy Resources. Energy storage technology that facilitates the integration of Renewable Energy Resources shall be eligible for these pilot programs. Energy conservation products, energy management products, energy efficiency products, or products that use non-renewable fuels shall not be eligible for these pilot programs.

R14-2-1804~~3~~. Renewable Energy Credits

A. One Renewable Energy Credit shall be created for each kWh derived from an Eligible Renewable Energy Resource.

B. For Distributed Renewable Energy Resources, one Renewable Energy Credit shall be created for each 3,415 British Thermal Units of heat produced by a Solar Water Heating System, a Solar Industrial Process Heating and Cooling System, Solar Space Cooling System, Biomass Thermal System, Biogas Thermal System, or a Solar Space Heating System.

C. An Affected Utility may transfer Renewable Energy Credits to another party and may acquire Renewable Energy Credits from another party. A Renewable Energy Credit is owned by the owner of the Eligible Renewable Energy Resource from which it was derived unless specifically transferred.

D. All transfers of Renewable Energy Credits shall be appropriately documented to demonstrate that the energy associated with the Renewable Energy Credits meets the provisions of R14-2-1803~~2~~.

E. Any contract by an Affected Utility for purchase or sale of energy or Renewable Energy Credits to meet the requirements of this Rule shall explicitly describe the transfer of rights concerning both energy and Renewable Energy Credits.

F. Except in the case of Distributed Renewable Energy Resources, Affected Utilities must demonstrate the delivery of energy from Eligible Renewable Energy Resources to their retail consumers such as by providing proof that the necessary transmission rights were reserved and utilized to deliver energy from Eligible Renewable Energy Resources to the Affected Utility's system, if transmission is required, or that the appropriate control area operators scheduled the energy from Eligible Renewable Energy Resources for delivery to the Affected Utility's system.

R14-2-1805~~4~~. Annual Renewable Energy Requirement

A. In order to ensure reliable electric service at reasonable rates, each Affected Utility shall be required to satisfy an Annual Renewable Energy Requirement by obtaining Renewable Energy Credits from Eligible Renewable Energy Resources.

B. An Affected Utility's Annual Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the retail kWh sold by the Affected Utility during that calendar year:

2006	1.25%
2007	1.50%
2008	1.75%
2009	2.00%
2010	2.50%
2011	3.00%
2012	3.50%
2013	4.00%
2014	4.50%
2015	5.00%
2016	6.00%
2017	7.00%
2018	8.00%
2019	9.00%
2020	12~~0~~.00%
2021	14~~1~~.00%
2022	16~~2~~.00%
2023	20~~13~~.00%
2024	24~~14~~.00%
~~After 2024~~ 2025	28~~15~~.00%
2025	28.00%
2026	32.00%
2027	36.00%
2028	40.00%
2029	45.00%
2030 and after	50.00%

The annual increase in the annual percentage for each Affected Utility will be pro rated for the first year based on when the Affected Utility's funding mechanism is approved.

C. An Affected Utility may use Renewable Energy Credits acquired in any year to meet its Annual Renewable Energy Requirement.

D. Once a Renewable Energy Credit is used by any Affected Utility to satisfy these requirements, the credit is retired and cannot be subsequently used to satisfy these rules or any other regulatory requirement.

E. If an Affected Utility trades or sells environmental pollution reduction credits or any other environmental attributes associated with kWh produced by an Eligible Renewable Energy Resource, the Affected Utility may not apply Renewable Energy Credits derived from that same kWh to satisfy the requirements of these rules.

~~F. No more than 20 percent of an Affected Utility's Annual Renewable Energy Requirement may be met with Renewable Energy Credits derived pursuant to R14-2-1807.~~

F~~G~~. An Affected Utility may ask the Commission to preapprove agreements to purchase energy or Renewable Energy Credits from Eligible Renewable Energy Resources.

R14-2-1806~~5~~. Distributed Renewable Energy Requirement

A. In order to improve system reliability, each Affected Utility shall be required to satisfy a Distributed Renewable Energy Requirement by ~~obtaining Renewable Energy Credits~~measuring production from Distributed Renewable Energy Resources.

B. An Affected Utility's Distributed Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the ~~Affected Utility's Annual Renewable Energy Requirement~~retail kWhs sold by the Affected Utility during that calendar year, with the addition of measured production from Distributed Renewable Energy Resources that is produced and consumed behind the meter:

2020~~07~~	4.0~~5~~%
2021~~08~~	4.6~~10~~%
2022~~09~~	5.2~~15~~%
2023~~10~~	5.8~~20~~%
2024~~11~~	6.4~~25~~%
2025~~After 2011~~	7.0~~30~~%
2026	7.6%
2027	8.2%
2028	8.8%
2029	9.4%
2030	10.0%

~~The annual increase in the annual percentage for each Affected Utility will be pro rated for the first year based on when the Affected Utility's funding mechanism is approved.~~

C. Production from Distributed Renewable Energy Resources will be measured for compliance with this requirement based on dedicated production meters installed by the Affected Utility at the customer's premise.~~An Affected Utility may use Renewable Energy Credits acquired in any year to meet its Distributed Renewable Energy Requirement. Once a Renewable Energy Credit is used by any Affected Utility to satisfy these requirements, the credit is retired.~~

D. Distributed Renewable Energy Resources that are not Community Distributed Generation must have a nameplate capacity of 50kW-DC or less to be counted toward compliance with the Distributed Renewable Energy Requirement.~~An Affected Utility shall meet one-half of its annual Distributed Renewable Energy Requirement from residential applications and the remaining one-half from non-residential, non-utility applications.~~

E. An Affected Utility may satisfy no more than 10 percent of its annual Distributed Renewable Energy Requirement from Community Distributed Generation owned by the Affected Utility.~~Renewable Energy Credits derived from distributed Renewable Energy Resources that are non-utility owned generators that sell electricity at wholesale to Affected Utilities. This Wholesale Distributed Generation Component shall qualify for the non-residential portion of the Distributed Renewable Energy Requirement.~~

~~F. Any Renewable Energy Credit created by production of renewable energy which the Affected Utility does not own shall be retained by the entity creating the Renewable Energy Credit. Such Renewable Energy Credit may not be considered used or extinguished by any Affected Utility without approval and proper documentation from the entity creating the Renewable Energy Credit, regardless of whether or not the Commission acknowledged the kWhs associated with non-utility owned Renewable Energy Credits.~~

~~G. The reporting of kWhs associated with Renewable Energy Credits not owned by the utility will be acknowledged.~~

~~**R14-2-1806. Extra Credit Multipliers**~~

~~A. Renewable Energy Credits derived from Eligible Renewable Energy Resources installed after December 31, 2005, shall not be eligible for Extra Credit Multipliers.~~

~~B. The extra Renewable Energy Credits resulting from any applicable multiplier shall be added to the Renewable Energy Credits produced by the Eligible Renewable Energy Resource to determine the total Renewable Energy Credits that may be used to meet an Affected Utility's Annual Renewable Energy Requirement.~~

~~C. "Early Installation Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource, a Solar Water Heater, a Solar Space Cooling system, a Landfill Gas Generator, a Wind Generator, or a Biomass Electricity Generator that was installed and began operations between January 1, 2001, and December 31, 2003, shall be eligible for an Early Installation Extra Credit Multiplier. Renewable Energy Credits derived from such facilities and acquired by Affected Utilities shall be eligible for five years following the facility's operational start-up. The multiplier shall vary according to the year in which the system began operating:~~

~~2001 .3~~

~~2002 .2~~
~~2003 .1~~

~~D. "In-state Power Plant Installation Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource that was installed in Arizona on or before December 31, 2005, shall be eligible for an In-state Power Plant Installation Extra Credit Multiplier. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied by .5 annually for the life of the facility. The extra Renewable Energy Credits resulting from the multiplier shall be added to the Renewable Energy Credits produced by the Eligible Renewable Energy Resource to determine the total Renewable Energy Credits that may be used to meet an Affected Utility's Annual Renewable Energy Requirement.~~

~~E. "In-state Manufacturing and Installation Content Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource, a Solar Water Heater, a Solar Space Cooling system, a Landfill Gas Generator, a Wind Generator, or a Biomass Electricity Generator that was installed in Arizona on or before December 31, 2005, and that contains components manufactured in Arizona shall be eligible for an In-state Manufacturing and Installation Content Extra Credit Multiplier. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied annually for the life of the facility by a factor determined by multiplying .5 times the percent of Arizona content of the total installed plant.~~

~~F. "Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Distributed Solar Electric Generator that was installed in Arizona on or before December 31, 2005, shall be eligible for a Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier if the facility meets at least two of the following criteria:~~

~~1. The facility is installed on customer premises,~~
~~2. The facility is included in any Affected Utility's approved Green Pricing program,~~
~~3. The facility is included in any Affected Utility's approved Net Metering or Net Billing program,~~
~~4. The facility is included in any Affected Utility's approved solar leasing program, or~~
~~5. The facility is owned by and located on an Affected Utility's property or customer property. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied by .5 annually for the life of the facility. Meters will be attached to each solar electric generator and read at least once annually to verify solar performance.~~

~~G. All multipliers are additive, except that the maximum combined Extra Credit Multiplier shall not exceed 2.0.~~

~~**R14-2-1807. Manufacturing Partial Credit**~~

~~A. An Affected Utility may acquire Renewable Energy Credits to apply to the non-distributed portion of its Annual Renewable Energy Requirement if it or its affiliate owns or makes a significant investment in any solar electric manufacturing plant located in Arizona or if it or its affiliate provides incentives to a manufacturer of solar electric products to locate a manufacturing facility in Arizona.~~

~~B. The Renewable Energy Credits shall be equal to the nameplate capacity of the solar electric generators produced and sold in a calendar year times 2,190 hours, which approximates a 25 percent capacity factor.~~

~~C. Extra credit multipliers shall not apply to Renewable Energy Credits created by this Section.~~

R14-2-18078. Tariff

A. Within 60 days of the effective date of these rules, each Affected Utility shall file with the Commission a Tariff in substantially the same form as the Sample Tariff set forth in these rules that proposes methods for recovering the reasonable and prudent costs of complying with these rules. The specific amounts in the Sample Tariff are for illustrative purposes only and Affected Utilities may submit, with proper support, Tariff filings with alternative surcharge amounts.

B. The Affected Utility's Tariff filing shall provide the following information:

1. Financial information and supporting data sufficient to allow the Commission to determine the Affected Utility's fair value for purposes of evaluating the Affected Utility's proposed Tariff. Information submitted in the format of the Annual Report required under R14-2-212(G)(4) will be the minimum information necessary for filing a Tariff application but Commission Staff may request additional information depending upon the type of Tariff filing that is submitted;
2. A discussion of the suitability of the Sample Tariff set forth in Appendix A for recovering the Affected Utility's reasonable and prudent costs of complying with these rules;
3. Data to support the level of costs that the Affected Utility contends will be incurred in order to comply with these rules;
4. Data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation; and
5. Any other information that the Commission believes will be relevant to the Commission's consideration of the Tariff filing.

C. The Commission will approve, modify, or deny a Tariff proposed pursuant to subsection (A) within 180 days after the Tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-18054(B), and Distributed Renewable Energy Requirement, as set forth in R14-2-18065(B), will be effective upon Commission approval of the Tariff filed pursuant to this Section.

D. If an Affected Utility has an adjustor mechanism for the recovery of costs related to Annual Renewable Energy Requirements, the Affected Utility may file a request to reset its adjustor mechanism in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all the information required by subsection (B), except that it may omit information specifically related to the fair value determination. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-1805~~4~~(B), and Distributed Renewable Energy Requirement, as set forth in R14-2-1806~~5~~(B), will be effective upon Commission approval of the adjustor mechanism rate filed pursuant to this Section.

E. An Affected Utility may file a rate case pursuant to R14-2-103 in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all information required by subsection (B).

F. For Eligible Renewable Energy Resources acquired by an Affected Utility after January 1, 2020, the Affected Utility shall recover the costs of those Eligible Renewable Energy Resources by the same method as the Affected Utility recovers its costs for Conventional Energy Resources.

R14-2-1808~~9~~. Customer Self-Directed Renewable Energy Option

A. By January 1, 2007, each Affected Utility shall file with Docket Control a Tariff by which an Eligible Customer may apply to an Affected Utility to receive funds to install distributed Renewable Energy Resources. The funds annually received by an Eligible Customer pursuant to this Tariff may not exceed the amount annually paid by the Eligible Customer pursuant to the Affected Utility's Tariff.

B. An Eligible Customer seeking to participate in this program shall submit to the Affected Utility a written application that describes the Renewable Energy Resources that it proposes to install and the projected cost of the project. An Eligible Customer shall provide at least half of the funding necessary to complete the project described in its application.

C. All Renewable Energy Credits derived from the project~~, including generation and Extra Credit Multipliers,~~ shall belong to the Affected Utility~~ applied to satisfy the Affected Utility's Annual Renewable Energy Requirement~~.

R14-2-18~~1~~09. Uniform Credit Purchase Program

A. The Director of the Utilities Division shall establish a Uniform Credit Purchase Program working group, which will study issues related to implementing Distributed Renewable Energy Resources. The working group shall address the consumer participation process, budgets, incentive levels, eligible technologies, system requirements, installation requirements, and any other issues that are relevant to encouraging the implementation of Distributed Renewable Energy Resources. No later than March 1, 2007, the Director of the Utilities Division shall file a staff report with recommendations for Uniform Credit Purchase Programs.

B. No later than July 1, 2007, each Affected Utility shall file a Uniform Credit Purchase Program for Commission review and approval.

R14-2-1810~~1~~. Net Metering and Interconnection Standards

The Commission Staff shall host a series of workshops addressing the issues of rate design including Net Metering and interconnection standards. Upon completion of this task, and the adoption of rules or standards, if appropriate, each Affected Utility shall file conforming Net Metering tariffs and interconnection standards in Docket Control.

R14-2-1811~~2~~. Renewable Energy Standard Compliance Reports

A. Beginning April 1, 2007, and every April 1st thereafter, each Affected Utility shall file with Docket Control a report that describes its compliance with the requirements of these rules for the previous calendar year and provides other relevant information. The Affected Utility shall also transmit to the Director of the Utilities Division an electronic copy of this report that is suitable for posting on the Commission's web site.

B. The compliance report shall include the following information:

1\. The actual kWh of energy produced within its service territory and the actual kWh of energy or equivalent obtained from Eligible Renewable Energy Resources, differentiating between kWhs for which the Affected Utility owns the Renewable Energy Credits and kWhs produced in the Affected Utility's service territory for which the Affected Utility does not own the Renewable Energy Credits;

2\. The actual kWh of energy obtained from Distributed Renewable Energy Resources;

3~~2~~. The kWh of energy or equivalent obtained from Eligible Renewable Energy Resources normalized to reflect a full year's production;

4\. The kWh of energy obtained from Distributed Renewable Energy Resources normalized to reflect a full year's production;

5~~3~~. The kW of generation capacity, disaggregated by technology type;

6~~4~~. Cost information regarding cents per actual kWh of energy obtained from Eligible Renewable Energy Resources and cents per kW of generation capacity, disaggregated by technology type;

7~~5~~. A breakdown of the Renewable Energy Credits used to satisfy~~ both~~ the Annual Renewable Energy Requirement ~~and the Distributed Renewable Energy Requirement~~ and appropriate documentation of the Affected Utility's receipt of those Renewable Energy Credits;~~ and~~

8~~6~~. A description of the Affected Utility's procedures for choosing Eligible Renewable Energy Resources and a certification from an independent auditor that those procedures are fair and unbiased and have been appropriately applied;~~.~~

9. A discussion of the type and scale of Eligible Renewable Resources proposed in or near communities, including but not limited to tribal communities, impacted by the Affected Utility's closure of a Conventional Energy Resource and reasons why those Renewable Energy Resources were chosen or rejected; and
10. Whether the costs of the Affected Utility's Eligible Renewable Energy Resources will be recovered through the renewable energy tariff or through a rate case.

C. The Commission may consider all available information and may hold a hearing to determine whether an Affected Utility's compliance report satisfied the requirements of these rules.

R14-2-18123. Renewable Energy Standard Implementation Plans

A. Beginning July 1, 2007, and every July 1st thereafter, each Affected Utility shall file with Docket Control for Commission review and approval a plan that describes how it intends to comply with these rules for the next calendar year. The Affected Utility shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's web site to the Director of the Utilities Division.

B. The implementation plan shall include the following information:
1. A description of the Eligible Renewable Energy Resources, identified by technology, proposed to be added by year for the next five years and a description of the kW and kWh to be obtained from each of those resources;
2. The estimated cost of each Eligible Renewable Energy Resource proposed to be added, including cost per kWh and total cost per year;
3. A description of the method by which each Eligible Renewable Energy Resource is to be obtained, such as self-build, customer installation, or request for proposals;
4. A description of the economic development opportunities for each Eligible Renewable Energy Resource proposed to be added in or near communities, including but not limited to tribal communities, impacted by the Affected Utility's closure of a Conventional Energy Resource;
5. A description of programs considered or proposed for incentivizing deployment of Distributed Renewable Energy Resources;
64. A proposal that evaluates whether the Affected Utility's existing rates allow for the ongoing recovery of the reasonable and prudent costs of complying with these rules, including a Tariff application that meets the requirements of R14-2-18078 and addresses the Sample Tariff set forth in Appendix A if necessary; and
75. A line item budget that allocates specific funding for Distributed Renewable Energy Resources, for the Customer Self-Directed Renewable Energy Option, for power purchase agreements, for utility-owned systems, and for each Eligible Renewable Energy Resource described in the Affected Utility's implementation plan.

C. The Commission may hold a hearing to determine whether an Affected Utility's implementation plan satisfies the requirements of these rules.

R14-2-18134. Electric Power Cooperatives

A. Within 60 days of the effective date of these rules, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year and a Tariff that proposes methods for recovering the reasonable and prudent costs of complying with its proposed plan and addresses the Sample Tariff set forth in Appendix A. The cooperative shall also transmit electronic copies of these filings that are suitable for posting on the Commission's web site to the Director of the Utilities Division. Upon Commission approval of this plan, its provisions shall substitute for the requirements of R14-2-18054 and R14-2-18065 for the electric power cooperative proposing the plan.

B. Beginning July 1, 2007, and every July 1st thereafter, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year. The cooperative shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's web site to the Director of the Utilities Division.

R14-2-18145. Enforcement and Penalties

A. If an Affected Utility fails to meet the annual requirements set forth in R14-2-18054 and R14-2-18065, it shall include with its annual compliance report a notice of noncompliance.

B. The notice of noncompliance shall provide the following information:
1. A computation of the difference between the Renewable Energy Credits required by R14-2-18054 and the kWh required by R14-2-18065 and the amount actually obtained,
2. A plan describing how the Affected Utility intends to meet the shortfall from the previous calendar year in the current calendar year, and
3. An estimate of the costs of meeting the shortfall.

C. If the Commission finds after affording an Affected Utility notice and an opportunity to be heard that the Affected Utility has failed to comply with its implementation plan approved by the Commission as set forth in R14-2-18123, the Commission may find that the Affected Utility shall not recover the costs of meeting the shortfall described in R14-2-18145(B) in rates.

D. If the Commission finds after affording an Affected Utility notice and opportunity to be heard that the Affected Utility has failed to retire a sufficient number of Clean Energy Credits at the end of a compliance period, the Commission may find that the Affected Utility shall not recover the costs of meeting the shortfall in rates.

ED. Nothing herein is intended to limit the actions the Commission may take or the penalties the Commission may impose pursuant to Arizona Revised Statutes, Chapter 2, Article 9. An Affected Utility is entitled to notice and an opportunity to be heard prior to Commission action or imposition of penalties.

R14-2-18156. Waiver from the Provisions of this Article

A. The Commission may waive compliance with any provision of this Article for good cause.

B. Any Affected Utility may petition the Commission to waive its compliance with any provision of this Article for good cause.

C. A petition for a waiver from these rules shall, at a minimum:

1. State the reason(s) for the waiver request;
2. Identify each section of this rule for which a waiver is requested;
3. Describe the effect the waiver will have on compliance with this rule;
4. Describe how the waiver will not compromise, or will further, the rule's purposes; and
5. Describe why the waiver would be a reasonable alternative to the rule's requirements.

DC. A petition filed pursuant to these rules shall have priority over other matters filed at the Commission.

~~10.~~11. "Demand response" means modification of customers' electricity consumption patterns, affecting the timing or quantity of customer demand and usage, achieved through intentional actions taken by an affected utility or customer.~~, because of changes in prices, market conditions, or threats to system reliability.~~

~~11.~~12. "Distributed generation" means the production of electricity on the customer's side of the meter, for use by the customer, through a technology~~process~~ such as solar photovoltaic panels or CHP.

~~12.~~13. "DSM" means demand-side management, the implementation and maintenance of one or more DSM programs that comprise a DSM portfolio.

14. "DSM measure" means any material, device, technology, educational program, ~~pricing option,~~ practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off-peak periods and includes CHP used to displace space heating, water heating, or another load.

~~13.~~15. "DSM portfolio" means the entire suite of DSM programs offered to residential customers, including low-income customers; or to non-residential customers.

~~14.~~16. "DSM program" means one or more DSM measures provided as part of a single offering to customers.

17. "DSM tariff" means a Commission-approved schedule of rates designed to recover an affected utility's reasonable and prudent costs of complying with this Article.

~~15.~~18. "Electric generation system" means all personal property and operating real property used for the purpose of generating electricity.

~~16.~~19. "Electric utility" means a public service corporation providing electric service to the public.

~~17.~~20. "Energy efficiency" means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end use customers.

~~18.~~21. "Energy efficiency standard" means the reduction in retail energy sales, in percentage of retail kWh ~~sales~~, required to be achieved through an affected utility's approved DSM ~~programs~~ portfolio as prescribed in R14-2-2404.

~~19.~~22. "Energy savings" means the reduction in a customer's energy consumption directly resulting from a DSM ~~program~~portfolio, expressed in kWh.

~~20.~~23. "Energy service company" means a company that provides a broad range of services related to energy efficiency, including energy audits, the design and implementation of energy efficiency projects, and the installation and maintenance of energy efficiency measures.

~~21.~~24. "Environmental benefits" means avoidance of costs for compliance, or reduction in environmental impacts, for things such as, but not limited to: a. Water use and water contamination, b. Monitoring storage and disposal of solid waste such as coal ash (bottom and fly), c. Adverse h~~H~~ealth effects from burning fossil fuels, and d. Pollutant e~~E~~missions from transportation and production of fuels and electricity. ~~"Fuel-neutral" means without promoting or otherwise expressing bias regarding a customer's choice of one fuel over another.~~

~~22.~~25. "Incremental benefits" means amounts saved through avoiding costs for fuel, purchased power, new generation capacity, transmission~~,~~ and distribution capacity, and other cost items necessary to provide electric utility service, along with other improvements in societal welfare, such as through avoided environmental impacts, including, but not limited to, water consumption savings, air emission reduction, reduction in coal ash, and reduction of nuclear waste.

~~23.~~26. "Incremental costs" means the additional expenses of a DSM ~~measures~~portfolio, relative to baseline.

~~24.~~27. "Independent program administrator" means an impartial third party employed to provide objective oversight of energy efficiency programs.

~~25.~~28. "kW" means kilowatt.

~~26.~~29. "kWh" means kilowatt-hour.

~~27.~~30. "Leveraging" means combining resources to more effectively achieve an energy efficiency goal, or to achieve greater energy efficiency savings, than would be achieved without combining resources.

~~28.~~31. "Load management" means actions taken or sponsored by an affected utility to reduce peak demands~~ or improve system operating efficiency~~, such as direct control of customer demands through ~~affected-~~utility-initiated interruption or cycling, thermal storage, or educational campaigns to encourage customers to shift loads.

~~29.~~32. "Low-income customer" means a customer with a below average level of household income, as defined in an affected utility's Commission-approved DSM ~~program~~ portfolio description.

~~30.~~33. "Market transformation" means strategic efforts to induce lasting structural or behavioral changes in the market that result in increased energy efficiency.

~~31.~~34. "Net benefits" means the incremental benefits resulting from DSM minus the incremental costs of DSM.

~~32.~~35. "Non-energy~~market~~ benefits" means improvements in societal welfare that are outside the scope of utility system benefits~~not bought or sold~~, including but not limited to increased productivity, increased comfort, increased property value, environmental benefits, reduced compliance costs, and water savings..

~~33.~~36. "~~Program~~ Portfolio costs" means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating a Commission-approved DSM ~~programs~~ portfolio.

~~34.~~37. "Self-direction" means an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments upon application by the customer.

~~35.~~38. "Societal Test" means a cost-effectiveness test ~~of the net benefits~~ of a DSM portfolio ~~programs~~ that ~~starts with the Total Resource Cost Test, but~~ includes both utility system and non-energy~~market~~ benefits and ~~,~~ both utility and customer costs to implement a DSM portfolio;, that usesing ~~including... and , costs to society, and~~ a social discount rate to determine the net present value of costs and benefits that is based on the yield for long-term U.S. Treasury securities up to a cap of 3%; that uses a non-energy benefits adder of at least 50% applied to the sum of other quantifiable benefits for low-income programs within a DSM portfolio; and that uses a non-energy benefits adder of at least 25% applied to the sum of other quantifiable benefits for all other programs within a DSM portfolio.

~~36.~~39. "Staff" means individuals working for the Commission's Utilities Division, whether as employees or through contract.

~~37.~~40. "Thermal envelope" means the collection of building surfaces, such as walls, windows, doors, floors, ceilings, and roofs, that separate interior conditioned (heated or cooled) spaces from the exterior environment.

~~38. "Total Resource Cost Test" means a cost-effectiveness test that measures the net benefits of a DSM program as a resource option, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.~~

R14-2-2402. Applicability

This Article applies to each affected utility classified as Class A according to R14-2-103(A)(3)(q), unless the affected utility is an electric distribution cooperative that has fewer than 25% of its customers in Arizona.

R14-2-2403. Goals and Objectives

A. An affected utility shall design each DSM ~~program~~ portfolio:
   1. To be cost-effective, and
   2. To accomplish ~~at least one of~~ the following:
      a. Energy efficiency,
      b. Load management, and/or demand response.
      ~~c.~~b. ~~Demand response.~~

B. An affected utility shall consider the following when planning and implementing a DSM ~~program~~portfolio:
   1. Whether the DSM ~~program~~portfolio will achieve cost-effective energy savings and peak demand reductions;
   2. Whether the DSM ~~program~~portfolio will advance market transformation and achieve sustainable savings, reducing the need for future market interventions; and
   3. Whether the affected utility can ensure a level of funding adequate to sustain the DSM ~~program~~ portfolio and allow the DSM ~~program~~ portfolio to achieve its targeted goal.

C. An affected utility shall:
   1. Offer DSM programs within a DSM portfolio that will provide an opportunity for all affected utility customer segments to participate, and
   2. Allocate ~~a portion of~~ not less than 5% of DSM portfolio resources specifically to low-~~-~~income customers.

R14-2-2404. Energy Efficiency Standards

A. Except as provided in R14-2-2418, in order to ensure reliable electric service at reasonable ratepayer rates and costs, by December 31, ~~2020~~2030, an affected utility shall, through cost effective DSM ~~energy efficiency programs~~portfolios, achieve cumulative annual energy savings, measured in kWh, equivalent to at least ~~22~~35% of the affected utility's retail electric energy sales for calendar year ~~2019~~2029 and in every year thereafter.

B. An affected utility shall, by the end of each calendar year, meet at least the cumulative annual energy efficiency standard listed in Table 1 for that calendar year. An illustrative example of how the required energy savings would be calculated is shown in Table 2. An illustrative example of how the standard could be met in ~~2020~~ 2030 is shown in Table 4.

Table 1. Energy Efficiency Standard

CALENDAR YEAR	ENERGY EFFICIENCY STANDARD (Cumulative Annual Energy Savings by the End of Each Calendar Year as a Percentage of the Retail Energy Sales in the Prior Calendar Year)
2011	1.25%
2012	3.00%
2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%
2021	23.30%
2022	24.60%
2023	25.90%
2024	27.20%
2025	28.50%
2026	29.80%
2027	31.10%
2028	32.40%
2029	33.70%
2030	35.00%

Table 2. Illustrative Example of Calculating Required Energy Savings

CALENDAR YEAR	A RETAIL SALES (kWh)	B ENERGY EFFICIENCY STANDARD	C REQUIRED CUMULATIVE ENERGY **SAVINGS** (B of current year × A of prior year)
2010	100,000,000		0
2011	100,750,000	1.25%	1,250,000
2012	101,017,500	3.00%	3,022,500
2013	101,069,925	5.00%	5,050,875
2014	100,915,646	7.25%	7,327,570
2015	100,821,094	9.50%	9,586,986
2016	100,517,711	12.00%	12,098,531
2017	100,293,499	14.50%	14,575,068
2018	100,116,043	17.00%	17,049,895
2019	99,986,628	19.50%	19,522,628
2020	99,902,384	22.00%	21,997,058
2021	100,841,388	23.30%	23,277,255
2022	101,785,056	24.60%	24,806,981
2023	102,748,740	25.90%	26,362,329
2024	103,732,607	27.20%	27,947,657
2025	104,736,836	28.50%	29,563,793
2026	105,761,611	29.80%	31,211,577
2027	106,807,126	31.10%	32,891,861
2028	107,873,584	32.40%	34,605,509
2029	108,961,195	33.70%	36,353,398
2030	110,070,178	35.00%	38,136,418

C. An affected utility's measured reductions in peak demand resulting from cost-effective demand response and load management programs may comprise up to ~~two~~ one percentage points of the ~~22~~35% energy efficiency standard through 20~~2~~30, with peak demand reduction capability from demand response converted to an annual energy savings equivalent based on its actual load factor ~~an assumed 510% annual load factor~~ or 4%, whichever is greater. The credit for demand response and load management peak demand reductions shall not exceed ~~10~~5% of the energy efficiency standard set forth in subsection (B) for any year through 20~~2~~30. ~~The measured reductions in peak demand occurring during a calendar year after the effective date of this Article may be counted for that calendar year even if the demand response or load management program resulting in the reductions was implemented prior to the effective date of this Article.~~

D. An affected utility's energy savings resulting from DSM energy efficiency programs implemented before the effective date of this Article, but after 2004, may be credited toward meeting the energy efficiency standard set forth in subsection (B) through 2020. The total energy savings credit for these pre-rules energy efficiency programs shall not exceed 4% of the affected utility's retail energy sales in calendar year 2005. A portion of the total energy savings credit for these pre-rules energy efficiency programs may be applied each year, from 2016 through 2020, as listed in Table 3, Column A.

Table 3. Credit for Pre-Rules Energy Savings

CALENDAR YEAR	A CREDIT FOR THE PRE-RULES ENERGY SAVINGS APPLIED IN EACH YEAR (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Shall Be Applied in the Year)	B CUMULATIVE APPLICATION OF THE CREDIT FOR THE PRE-RULES ENERGY SAVINGS IN 2016-2020 (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Are Credited by the End of Each Year)
2016	7.5%	7.5%
2017	15.0%	22.5%
2018	20.0%	42.5%
2019	25.0%	67.5%
2020	32.5%	100.0%

E. An affected utility may count toward meeting the standard up to one-third of the energy savings~~.~~ resulting from energy efficiency building codes and energy efficiency appliance standards, provided that the affected utility played a direct role in achieving the savings ~~and reductions~~ through DSM program implementation. The partial credit for building code energy savings or energy efficiency appliance standards ~~and reductions~~ shall be ~~that are~~ quantified and reported through a measurement and evaluation study undertaken by the affected utility and shall be commensurate with the direct role that the affected utility played to achieve the savings ~~and reductions~~ through DSM program implementation.

F. An affected utility may count the energy savings from combined heat and power (CHP) ~~installation~~systems that do not qualify under the Renewable Energy Standard toward meeting the energy efficiency standard, provided that the affected utility played a direct role in supporting the implementation of a CHP system ~~achieving the savings and reductions~~ through DSM program implementation. The credit for savings from CHP shall be quantified and reported through a measurement and evaluation study undertaken by the affected utility and shall be commensurate with the direct role that the affected utility played to achieve the savings through DSM program implementation.

G. An affected utility may count a customer's energy savings resulting from self-direction toward meeting the standard.

H. With the exception of conservation voltage reduction, an affected utility's energy savings resulting from efficiency improvements to its ~~delivery or~~ transmission or distribution system may not be counted toward meeting the standard.

~~H.~~I. An affected utility's energy savings resulting from efficiency improvements made directly to its electric generation system, including heat rate improvements to power plants, may not be counted toward meeting the standard.

~~I.~~J. An affected utility's energy savings used to meet the energy efficiency standard will be assumed to continue through the year 203~~2~~0 or, if expiring before the year 203~~2~~0, to be replaced with a DSM ~~energy efficiency~~ portfolio and programs having at least the same level of efficiency.

Table 4. Illustrative Example of How the Energy Standard Could Be Met in ~~2020~~2030

	203~~2~~0 Energy Efficiency Standard	202~~1~~9 Retail Sales (kWh)	Required Cumulative Annual Energy Savings (kWh)
Total	~~22~~35.00%	108,961,195~~99,986,628~~	38,136,418~~21,997,058~~
Breakdown of Savings and Credits Used To Meet ~~2020~~ 2030 Standard:			
			Cumulative Annual Energy Savings or Credit (kWh)
Demand Response Credit R14-2-2404(C)	Up to ~~2~~1.00%		1,089,612~~1,999,733~~
Pre-rules Savings Credit R14-2-2404(D)			1,100,000*
Building Code R14-2-2404(E)			1,000,000
CHP R14-2-2404(F)			500,000
Self-direction R14-2-2404(G)			100,000
Energy Efficiency R14-2-2404(A)			34,346,806~~17,297,325~~
Total			38,136,418~~21,997,058~~
*The total pre-rules savings credit is capped at 4% of 2005 retail energy sales, and the total credit is allocated over five years from 2016 to 2020. The credit shown above represents an estimate of the portion of the total credit that can be taken in 2020, or 32.5% of the total credit allowed.			

R14-2-2405. Implementation Plans

A. Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.

B. The implementation plan shall include the following information:
   1. Except for the initial implementation plan, a description of the affected utility's compliance with the requirements of this Article for the previous calendar year;
   2. Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary;
   3. Except for the initial implementation plan, which shall describe only the next calendar year, a description of each DSM program within a DSM portfolio to be newly implemented or continued in the next two calendar years and an estimate of the annual kWh and kW savings projected to be obtained through each DSM portfolio and program;
   4. The estimated total cost and cost per kWh reduction of each DSM measure, program, and portfolio ~~and DSM program~~ described in subsection (B)(3);
   5. A DSM tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable; and
   6. For each new DSM program or DSM measure that the affected utility desires to implement within a DSM portfolio, a program proposal complying with R14-2-2407.

C. An affected utility shall notify its customers of its annual implementation plan filing through a notice in its next regularly scheduled customer bills.

D. The Commission may hold a hearing to determine whether an affected utility's implementation plan satisfies the requirements of this Article within 180 days after such implementation plan is filed with the Commission. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.

E. An affected utility's Commission-approved implementation plan, and the DSM portfolio and programs authorized thereunder, shall continue in effect until the Commission takes action on a new implementation plan for the affected utility.

~~E.~~F. A utility shall not implement any program changes proposed in an implementation plan until such changes are approved by the Commission.

R14-2-2406. DSM Tariffs

A. An affected utility's DSM tariff filing shall include the following:
   1. A detailed description of each method proposed by the affected utility to recover the reasonable and prudent costs associated with implementing the affected utility's intended DSM ~~programs~~portfolio;
   2. Financial information and supporting data sufficient to allow the Commission to determine the affected utility's fair value, including, at a minimum, the information required to be submitted in a utility annual report filed under R14-2-212(G)(4);
   3. Data supporting the level of costs that the affected utility believes will be incurred in order to comply with this Article; and
   4. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.

B. The Commission shall approve, modify, or deny a tariff filed pursuant to subsection (A) within 180 days after the tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.

C. If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing a DSM ~~programs~~ portfolio, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and (3).

R14-2- 2407. Commission Review and Approval of DSM Programs and DSM Measures

A. An affected utility shall obtain Commission approval before implementing a new DSM program ~~or DSM measure~~.

B. An affected utility may apply for Commission approval of a DSM program ~~or DSM measure~~ by submitting a ~~program~~ proposal either as part of its DSM portfolio implementation plan submitted under R14-2-2405 or through a separate application that identifies the DSM portfolio under which the DSM program will be added.

C. A DSM portfolio or program proposal shall include the following:
   1. A description of the DSM programs ~~or~~ and DSM measures that the affected utility desires to implement as part of the DSM portfolio,
   2. The affected utility's objectives and rationale for the DSM programs and portfolio ~~or DSM measure~~,
   3. A description of the market segment at which the DSM programs and ~~or DSM measure~~ portfolio is aimed,
   4. An estimated level of customer participation in the DSM programs and portfolio ~~or DSM measure~~,
   5. An estimate of the baseline for the components of the DSM portfolio,
   6. The estimated societal benefits and savings from the DSM programs and portfolio ~~or DSM measure~~,
   7. The estimated societal costs of the DSM programs and portfolio ~~or DSM measure~~,
   8. The estimated environmental benefits to be derived from the DSM programs and portfolio ~~or DSM measure~~,
   9. The estimated benefit-cost ratio of the DSM programs and portfolio ~~or DSM measure~~,
   10. The affected utility's marketing and delivery strategy,
   11. The affected utility's estimated annual costs and budget for the DSM programs and portfolio, ~~or DSM measure,~~
   12. The implementation schedule for the DSM programs and portfolio, ~~or DSM measure,~~
   13. A description of the affected utility's plan for monitoring and evaluating the DSM programs and portfolio ~~or DSM measure~~, and
   14. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.

D. In determining whether to approve a ~~program~~ DSM proposal, the Commission shall consider:
   1. The extent to which the Commission believes the DSM ~~program or DSM measure~~ portfolio will meet the goals set forth in R14-2-2403(A), and
   2. All of the considerations set forth in R14-2-2403(B).

E. Staff may request modifications of an on-going DSM portfolio or DSM programs within a DSM portfolio to ensure consistency with this Article. The Commission shall allow affected utilities adequate time to notify customers of ~~DSM program~~ modifications.

R14-2-2408. Parity and Equity

A. An affected utility shall develop and propose DSM programs within DSM portfolios for:

1. R~~r~~esidential customers, including low-income customers, and
2. N~~n~~on-residential customers~~, and low-income customers,~~.

~~A.~~B. No less than 5% of the total DSM budget shall be devoted to programs or program components for low-income customers.

C. An affected utility shall allocate DSM funds collected from residential customers and from non-residential customers proportionately to those customer classes to the extent practicable.

~~B.~~D. The affected utility costs of DSM programs for low-income customers shall be borne by all customer classes, except where a customer or customer class is specifically exempted by Commission order.

~~C.~~E. DSM funds collected by an affected utility shall be used, to the extent practicable, to benefit that affected utility's customers.

~~D.~~F. All customer classes of an affected utility shall bear the costs of DSM~~programs~~ by payment through a non-bypassable mechanism, unless a customer or customer class is specifically exempted by Commission order.

R14-2-2409. Reporting Requirements

A. By March 1 of each year, an affected utility shall submit to the Commission, in a Commission-established docket for that year, a DSM progress report providing information for each of the affected utility's Commission-approved DSM portfolios and programs within each portfolio and including at least the following:

1. An analysis of the affected utility's progress toward meeting the annual energy efficiency standard;
2. A list of the affected utility's current Commission-approved DSM portfolios and programs within each portfolio ~~and DSM measures~~, organized by customer segment;
3. A description of the findings from any research projects completed during the previous year; and
4. The following information for each Commission-approved DSM portfolio and programs within each portfolio ~~or DSM measure~~:
    a. A brief description;
    b. Goals, objectives, and savings targets;
    c. The level of customer participation during the previous year;
    d. The costs incurred during the previous year, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;
    e. A description and the results of evaluation and monitoring activities during the previous year;
    f. Savings realized in kW, kWh, therms, and BTUs, as appropriate;
    g. The environmental and non-energy benefits realized, including reduced emissions and water savings;
    h. Incremental benefits and net benefits, in dollars;
    i. Performance-incentive calculations for the previous year;
    j. Problems encountered during the previous year and proposed solutions;
    k. A description of any modifications proposed for the following year; and
    l. Whether the affected utility proposes to terminate ~~the~~ any DSM program within a DSM portfolio ~~or DSM measure~~ and the proposed date of termination.

B. By September 1 of each year, an affected utility shall file a status report including a tabular summary showing the following for each current Commission-approved DSM portfolio and program within each portfolio ~~and DSM measure~~ of the affected utility:

1. Semi-annual expenditures compared to annual budget, and
2. Participation rates.

C. An affected utility shall file each report required by this Section with Docket Control, where it will be available to the public, and shall make each such report available to the public upon request.

D. An affected utility may request within its implementation plan that these reporting requirements supersede specific existing DSM reporting requirements.

R14-2-2410. Cost Recovery

A. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM ~~program or~~ portfolio and programs within a DSM portfolio or ~~DSM measure~~ if the DSM portfolio ~~program or DSM measure~~ is all of the following:

1. Approved by the Commission before it is implemented,
2. Implemented in accordance with a Commission-approved program proposal or implementation plan, and
3. Monitored and evaluated for cost-effectiveness pursuant to R14-2-2415.

B. An affected utility shall monitor and evaluate each DSM portfolio and program ~~and DSM measureportfolio~~, as provided in R14-2-2415, to determine whether the DSM ~~program or DSM measure~~ portfolio is cost-effective and otherwise meets expectations.

C. If an affected utility determines that a DSM ~~program or DSM measure~~ portfolio is not cost-effective or otherwise does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2409 a proposal to modify or terminate the DSM ~~program or DSM measure~~ portfolio.

D. An affected utility shall recover its DSM costs concurrently, on an annual basis, with the spending for a DSM ~~program or DSM measure~~portfolio, unless the Commission orders otherwise.

E. An affected utility may recover costs from DSM funds for any of the following items, if the expenditures will enhance DSM:

1. Incremental labor attributable to DSM development,
2. A market study,
3. A research and development project such as applied technology assessment,
4. Consortium membership, or
5. Another item that is difficult to allocate to an individual DSM ~~program~~ portfolio.

F. The Commission may impose a limit on the amount of DSM funds that may be used for the items in subsection (E).

G. If goods and services used by an affected utility for DSM have value for other affected utility functions, programs, or services, the affected utility shall divide the costs for the goods and services and allocate funding proportionately.

H. An affected utility shall allocate DSM costs in accordance with generally accepted accounting principles.

I. The Commission shall review and address financial disincentives, recovery of fixed costs, and recovery of net lost income/revenue, due to Commission-approved DSM ~~programs~~portfolios and programs, if an affected utility requests such review in its rate case and provides documentation/records supporting its request in its rate application.

J. An affected utility, at its own initiative, may submit to the Commission twice-annual reports on the financial impacts of its Commission-approved DSM portfolios and programs, including any unrecovered fixed costs and net lost income/revenue resulting from its Commission-approved DSM portfolios and programs.

R14-2-2411. Performance Incentives

In the implementation plans required by R14-2-2405, an affected utility may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in R14-2-2404. The Commission may also consider performance incentives in a general rate case.

R14-2-2412. Cost-effectiveness

A. An affected utility shall ensure that the incremental benefits to society of the affected utility's overall DSM portfolio exceed the incremental costs to society of the DSM portfolio.

B. The overall DSM portfolio shall be evaluated to determine cost-effectiveness using the societal test. ~~The Societal Test shall be used to determine cost-effectiveness.~~

C. The analysis of a DSM ~~program's or DSM measure's~~ portfolio's cost-effectiveness may include:
   1. Costs and benefits associated with reliability, improved system operations, environmental impacts, and customer service;
   2. Savings of both natural gas and electricity; and
   3. Any uncertainty about future streams of costs or benefits.

D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively. ~~An affected utility, Staff, or any party may propose monetized benefits and costs if supported by appropriate documentation or analyses.~~

E. For purposes of analyzing DSM portfolio cost-effectiveness, m~~M~~arket transformation programs within a DSM portfolio shall be evaluated ~~analyzed for cost-effectiveness~~ by measuring market effects compared to program costs.

F. For purposes of analyzing DSM portfolio cost-effectiveness, e~~E~~ducational programs that support consumer and business adoption of energy efficiency, load management or demand response measures are not required to be cost effective and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test. ~~shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy.~~

G. For purposes of analyzing DSM portfolio cost-effectiveness, r~~R~~esearch and development and pilot programs are not required to ~~demonstrate~~ be cost-effective~~ness~~ and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test.

H. For purposes of evaluating DSM portfolio cost-effectiveness, a~~A~~n affected utility's low-income customer programs ~~portfolio shall is~~are not required to be cost-effective and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test.~~but costs attributable to necessary health and safety measures shall not be used in the calculation.~~

R14-2-2413. Baseline Estimation

A. To determine the baseline, an affected utility shall estimate the level of electric demand and consumption and the associated costs that would have occurred in the absence of a DSM portfolio, including the DSM programs or DSM measures within a DSM portfolio.

B. For demand response programs, an affected utility shall use customer load profile information to verify baseline consumption patterns and the peak demand savings resulting from demand response actions.

C. For installations or applications that have multiple fuel choices, an affected utility shall determine the baseline using the same fuel source actually used for the installation or application.

R14-2-2414. Fuel Neutrality

~~A. Ratepayer-funded DSM shall be developed and implemented in a fuel-neutral manner.~~

~~B.~~A. An affected utility shall use DSM funds collected from electric customers for electric DSM programs, unless otherwise ordered by the Commission.

~~C.~~B. An affected utility may use DSM funds collected from electric customers for thermal envelope improvements.

R14-2-2415. Monitoring, Evaluation, and Research

A. An affected utility shall monitor and evaluate each DSM ~~program and DSM measure~~portfolio to:
   1. Ensure compliance with the cost-effectiveness requirements of R14-2-2412;
   2. Determine participation rates, energy savings, and demand reductions;
   3. Assess the implementation process for the DSM ~~program or DSM measure~~portfolio;
   4. Obtain information on whether to continue, modify, or terminate a DSM program ~~or DSM measure~~ within a DSM portfolio; and
   5. Determine the persistence and reliability of the affected utility's DSM.

B. An affected utility may conduct evaluation and research, such as market studies, market research, and other technical research, for DSM program planning, product development, and DSM program improvement within a DSM portfolio.

R14-2-2416. Program Administration and Implementation

A. An affected utility may use an energy service company or other external resource to implement a DSM program or DSM measure within a DSM portfolio.

B. The Commission may, at its discretion, establish independent program administrators who would be subject to the relevant requirements of this Article.

R14-2-2417. Leveraging and Cooperation

A. An affected utility shall, to the extent practicable, participate in cost sharing, leveraging, or other lawful arrangements with customers, vendors, manufacturers, government agencies, other electric utilities, or other entities if doing so will increase the effectiveness or cost-effectiveness of a DSM portfolio~~program or DSM measure~~.

B. An affected utility shall participate in a DSM program ~~or DSM measure~~ with a natural gas utility when doing so is practicable and if doing so will increase the effectiveness or cost-effectiveness of a DSM ~~program or DSM measure~~portfolio.

R14-2-2418. Compliance by Electric Distribution Cooperatives

A. An electric distribution cooperative that is an affected utility shall comply with the requirements of this Section instead of meeting the requirements of R14-2-2404(A) and (B) and R14-2-2405(A).

B. An electric distribution cooperative shall, on June 1 of each odd year, or annually at its election:
   1. File with Docket Control, for Commission review and approval, an implementation plan for each DSM ~~program~~ portfolio and programs within a portfolio to be implemented or maintained during the next one or two calendar years, as applicable; and
   2. Submit to the Director of the Commission's Utilities Division an electronic copy of its implementation plan in a format suitable for posting on the Commission's web site.
   3. An implementation plan submitted under subsection (B) shall set forth an energy efficiency goal for each year of at least 75% of the savings requirement specified in R14-2-2404 and shall include the information required under R14-2-2405(B).
   ~~3.~~4. Submit annual DSM reports in accordance with the requirements in R14-2-2409.

R14-2-2419. Waiver from the Provisions of this Article

A. The Commission may waive compliance with any provision of this Article for good cause.

B. An affected utility may petition the Commission to waive its compliance with any provision of this Article for good cause.

C. A petition filed pursuant to this Section shall have priority over other matters filed under this Article.

APPENDIX B

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 7. RESOURCE PLANNING AND PROCUREMENT

Section

R14-2-701 Statement of Purpose

This Article lays out the requirements for a comprehensive and robust Integrated Resource Planning process. The Integrated Resource Plan ("IRP") will consider all reasonable resources to satisfy the demand for electricity services during a fifteen (15)-year planning period, taking into account both supply- and demand-side electric power resources. In broad terms, the IRP will include an assessment of the planning environment, a careful and detailed study of a range of future load forecasts, present generation resources, present demand resources, current investments in electricity conservation technologies, existing transmission and distribution facilities, and the relevant forecast and scenario analyses in support of a load-serving entity's selected resource plan. It will also contain a discussion of all applicable laws and regulations to ensure that the proposed Action Plan for the implementation of the selected resource plan complies with all laws and regulations of the Federal government and the State of Arizona.

The purpose of this Article is to ensure that the IRP serves as an adequate and useful tool to guarantee the orderly and integrated development of Arizona's electric power system, and to improve the system's reliability, resiliency, efficiency, and transparency, as well as the provision of electric power services at reasonable prices. The provisions established herein will guide the IRP process along lines that are consistent with the mandates for the Commission and following the electric power industry's best practices in integrated resource planning. This regulation, moreover, defines the terms related to the information required in the IRP, the procedures before the Commission, and the performance metrics guidelines and inducements that load-serving entities will follow after the Commission has evaluated and reviewed the IRP. The Commission will evaluate the IRP as well as each load-serving entity's performance thereafter in accordance with the provisions set forth in this regulation.

This regulation shall be interpreted in a way that promotes the highest public good and the protection of the interests of the residents of Arizona, and in such a way that the proceedings are carried out rapidly, justly, and economically.

R14-2-702. Definitions

In this Article, unless otherwise specified:

1. "Action Plan" refers to a plan that identifies the specific needs and potential actions that a load-serving entity will perform during the first five (5) years of the Planning Period in order to implement the Preferred Resource Plan.
2. "Acknowledgment" means a Commission determination, under R14-2-704, that an Integrated Resource Plan meets the requirements of this Article.
3. "Affiliated" means related through ownership of voting securities, through contract, or otherwise in such a manner that one entity directly or indirectly controls another, is directly or indirectly controlled by another, or is under direct or indirect common control with another entity.
4. "All-source Request for Proposals" or "all-source RFP" means a process wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants. The RFP shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFP shall consider demand-side resources on equal footing as supply-side ones and shall not be limited to "dispatchable" resources.
5. "All-source Request for Information" or "all-source RFI" means a process wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants. The RFI shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFI shall consider demand-side resources on equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

6. "Benchmark" means to calibrate against a known set of values or standards.
7. "Book life" means the expected time period over which a power supply source will be available for use by a load-serving entity.
8. "Btu" means British thermal unit.
9. "Capacity" means the amount of electric power, measured in megawatts, that a power source is rated to provide.
10. "Capacity Expansion Model" refers to a computer model designed to seek a least cost, or "optimal", portfolio of electricity supply- and demand-side resources that meets the utility's load forecast, accounting for system constraints and the need to maintain the reliability of the system over the planning period in the Preferred Resource Plan.
11. "Capital costs" means the construction and installation cost of facilities, including land, land rights, structures, and equipment.
12. "Coincident peak" means the maximum of the sum of two or more demands that occur in the same demand interval, which demand interval may be established on an annual, monthly, or hourly basis.
13. "Commission" or "ACC" refers to the Arizona Corporation Commission.
14. "Customer class" means a subset of customers categorized according to similar characteristics, such as amount of energy consumed; amount of demand placed on the energy supply system at the system peak; hourly, daily, or seasonal load pattern; primary type of activity engaged in by the customer, including residential, commercial, industrial, agricultural, and governmental; and location.
15. "Decommissioning" means the process of safely and economically removing a generating unit from service.
16. "Demand management" means beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage.
17. "Derating" means a reduction in a generating unit's capacity.
18. "Discount rate" means the interest rate used to calculate the present value of a cost or other economic variable.
19. "Docket Control" means the office of the Commission that receives all official filings for entry into the Commission's public electronic docketing system.
20. "Emergency" means an unforeseen and unforeseeable condition that:
    a. Does not arise from the load-serving entity's failure to engage in good utility practices,
    b. Is temporary in nature, and
    c. Threatens reliability or poses another significant risk to the system.
21. "End use" means the final application of electric energy, for activities such as, but not limited to, heating, cooling, running an appliance or motor, an industrial process, or lighting.
22. "Energy losses" means the quantity of electric energy generated or purchased that is not available for sale to end users, for resale, or for use by the load-serving entity.
23. "Escalation" means the change in costs due to inflation, changes in manufacturing processes, changes in availability of labor or materials, or other factors.
24. "Generating unit" means a specific device or set of devices that converts one form of energy (such as heat or solar energy) into electric energy, such as a turbine and generator or a set of photovoltaic cells.
25. "Heat rate" means a measure of generating station thermal efficiency expressed in Btus per net kilowatt-hour and computed by dividing the total Btu content of fuel used for electric generation by the kilowatt-hours of electricity generated.
26. "Independent monitor" means a company or consultant that is not affiliated with a load-serving entity and that is selected to oversee the conduct of a competitive procurement process under R14-2-706.
27. "Integrated Resource Plan" or "IRP" means a plan that considers all reasonable resources to satisfy the demand for electric power services during a specific period of time, including those relating to the offering of electric power, whether existing, traditional, and/or new resources, and those relating to energy demand such as energy conservation and efficiency or demand response and localized energy generation by the customer, while recognizing the obligation of compliance with laws and regulations that constrain resource selection.
28. "Integration" means methods by which energy produced by intermittent resources can be incorporated into the electric grid.
29. "Intermittent resources" means electric power generation for which the energy production varies in response to naturally occurring processes like wind or solar intensity.
30. "Interruptible power" means power made available under an agreement that permits curtailment or cessation of delivery by the supplier.
31. "In-service date" means the date a power supply source becomes available for use by a load-serving entity.
32. "Load-serving entity" means a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined.
33. "Long-term" means having a duration of three or more years.
34. "Major change" means any new procurement effort or addition, retirement or modification of generation plant having a nameplate capacity of 50 megawatts or greater; the addition of pollution control equipment; the unanticipated termination of a Power Purchase Agreement; or other event, such as a major forest fire, as set forth by the Commission.
35. "Major Project" shall mean any project greater than 50 megawatts.
36. "Maintenance" means the repair of generation, transmission, distribution, administrative, and general facilities; replacement of minor items; and installation of materials to preserve the efficiency and working condition of facilities.
37. "Mothballing" means the temporary removal of a generating unit from active service and accompanying storage activities.
38. "Operate" means to manage or otherwise be responsible for the production of electricity by a generating facility, whether that facility is owned by the operator, in whole or in part, or by another entity.
39. "Participation rate" means the proportion of customers who take part in a specific program.

40. "Planning Period" means the fifteen (15)-year period in an Integrated Resource Plan for which resources must be planned to meet customer load requirements.
41. "Planning Reserve Margin" refers to the reserve margin required to operate a load-serving entity's system reliably.
42. "Preferred Resource Plan" means a portfolio of resource additions selected by a load-serving entity from amongst those evaluated in the IRP representing the best performing resource mix to be implemented in the Action Plan.
43. "Probabilistic analysis" means a systematic evaluation of the effect, on costs, reliability, or other measures of performance, of possible events affecting factors that influence performance, considering the likelihood that the events will occur.
44. "Production cost" means the variable operating costs and maintenance costs of producing electricity through generation, including fuel cost, plus the cost of purchases of power sufficient to meet demand.
45. "Reference Case" refers to the forecast of load and associated system requirements, commodity prices, capital costs and risks representing a load-serving entity's best understanding of expected circumstances or median probability outcomes.
46. "Refurbish" means to make major changes, more extensive than maintenance or repair, in the power production, transmission, or distribution characteristics of a component of the power supply system, such as by changing the fuels that can be used in a generating unit or changing the capacity of a generating unit.
47. "Reliability" means a measure of the ability of a load-serving entity's generation, transmission, or distribution system to provide power without failures, measured to reflect the portion of time that a system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.
48. "Renewable energy resource" means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
49. "Reserve requirements" means the capacity that a load-serving entity must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, emergencies, system operating requirements, and reserve sharing arrangements.
50. "Reserve sharing arrangement" means an agreement between two or more load-serving entities to provide backup capacity.
51. "Resource Plan" refers to a selection of supply-side, demand-side, and transmission resources that best serves a load-serving entity's needs under a given forecast scenario.
52. "Resource planning" means integrated supply and demand analyses completed as described in this Article.
53. "RFP" means request for proposals.
54. "Self generation" means the production of electricity by an end user.
55. "Sensitivity analysis" means a systematic assessment of the degree of response of costs, reliability, or other measures of performance to changes in assumptions about factors that influence performance.
56. "Short-term" means having a duration of less than three years.
57. "Socioeconomic effects" means changes in the social and economic environments, including, for example, job creation, effects on local economies, geographical concentration of persons and structures, concentration of investment capital, and the ability of low-income and rental households to receive conservation services.
58. "Spinning reserve" means the capacity a load-serving entity must maintain connected to the system and ready to deliver power promptly in the event of an unexpected loss of generation source, expressed as a percentage of peak load, a percentage of the largest generating unit, or in fixed megawatts.
59. "Staff" means individuals working for the Commission's Utilities Division, whether as employees or through contract.
60. "Third-party independent energy broker" means an entity, such as Prebon Energy or Tradition Financial Services, that facilitates an energy transaction between separate parties without taking title to the transaction.
61. "Third-party online trading system" means a computer-based marketplace for commodity exchanges provided by an entity that is not affiliated with the load-serving entity, such as the Intercontinental Exchange, California Independent System Operator, or New York Mercantile Exchange.
62. "Total cost" means all capital, operating, maintenance, fuel, and decommissioning costs, plus the costs associated with mitigating any adverse environmental effects, incurred by end users, load-serving entities, or others, in the provision or conservation of electric energy services.

R14-2-703. Applicability

A. This Article applies to each load-serving entity, whether the power generated is for sale to end users or is for resale.

B. An electricity public service corporation that becomes a load-serving entity by increasing its generating capacity to at least 50 megawatts combined shall provide written notice to the Commission within 30 days after the increase and shall comply with the filing requirements in this Article within two years after the notice is filed.

C. The Commission may, by Order, exempt a load-serving entity from complying with any provision in this Article, or the Article as a whole, upon determining that:

1. The burden of compliance with the provision, or the Article as a whole, exceeds the potential benefits to customers in the form of cost savings, service reliability, risk reductions, or reduced environmental impacts that would result from the load-serving entity's compliance with the provision or Article; and
2. The public interest will be served by the exemption.

D. A load-serving entity that desires an exemption shall submit to Docket Control an application that includes, at a minimum:

1. The reasons why the burden of complying with the Article, or the specific provision in the Article for which exemption is requested, exceeds the potential benefits to customers that would result from the load-serving entity's compliance with the provision or Article;

2. Data supporting the load-serving entity's assertions as to the burden of compliance and the potential benefits to customers that would result from compliance; and
3. The reasons why the public interest would be served by the requested exemption.

R14-2-704. Load-serving Entity Annual Reporting Requirements

A. **Demand-Side Data:** A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of demand-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:
   1. Hourly demand for the previous calendar year, disaggregated by:
      a. Sales to end users;
      b. Sales for resale;
      c. Energy losses; and
      d. Other disposition of energy, such as energy furnished without charge and energy used by the load-serving entity;
   2. Coincident peak demand (megawatts) and energy consumption (megawatt-hours) by month for the previous 10 years, disaggregated by customer class;
   3. Number of customers by customer class for each of the previous 10 years; and
   4. Reduction in load (kilowatt and kilowatt-hours) in the previous calendar year due to existing demand management measures, by type of demand management measure.

B. **Supply-Side Data:** A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of supply-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:
   1. For each generating unit and purchased power contract for the previous calendar year:
      a. In-service date and book life or contract period;
      b. Type of generating unit or contract;
      c. The load-serving entity's share of the generating unit's capacity, or of capacity under the contract, in megawatts;
      d. Maximum generating unit or contract capacity, by hour, day, or month, if such capacity varies during the year;
      e. Annual capacity factor (generating units only);
      f. Average heat rate of generating units and, if available, heat rates at selected output levels;
      g. Average fuel cost for generating units, in dollars per million Btu for each type of fuel;
      h. Other variable operating and maintenance costs for generating units, in dollars per megawatt hour;
      i. Purchased power energy costs for long-term contracts, in dollars per megawatt-hour;
      j. Fixed operating and maintenance costs of generating units, in dollars per megawatt;
      k. Demand charges for purchased power;
      l. Fuel type for each generating unit;
      m. Minimum capacity at which the generating unit would be run or power must be purchased;
      n. Whether, under standard operating procedures, the generating unit must be run if it is available to run;
      o. Description of each generating unit as base load, intermediate, or peaking;
      p. Environmental impacts, including air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt-hour) for carbon dioxide, nitrogen oxides, sulfur dioxide, mercury, particulates, and other air emissions subject to current or expected future environmental regulation;
      q. Water consumption quantities and rates; and
      r. Tons of coal ash produced per generating unit;
   2. For the power supply system for the previous calendar year:
      a. A description of generating unit commitment procedures;
      b. Production cost;
      c. Reserve requirements;
      d. Spinning reserve;
      e. Reliability of generating, transmission, and distribution systems;
      f. Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short-term contracts; and
      g. Energy losses;
   3. The capacity, type, location(s), and expected term of demand-side resources offered in the load-serving entity's service area for the previous calendar year:
      a. By or on behalf of the utility;
      b. Through government-sponsored programs; or
      c. Through self generation; and
   4. An explanation of any resource procurement processes used by the load-serving entity during the previous calendar year that did not include use of an RFP, including the exception under which the process was used.

R14-2-705. Integrated Resource Planning Process

A. Planning Period: Effectiveness

1. The IRP shall consider a planning period of fifteen (15) years.
2. An IRP acknowledged by the Commission shall remain in effect until the acknowledgment of a subsequent IRP by the Commission, or until otherwise established by the Commission through resolution or order.
3. Any proposal for a new IRP, or any proposed update, review, or amendment to an existing IRP must be submitted to the Commission for evaluation and acknowledgment. An update, revision, or amendment to an IRP, in whole or in part, will not enter into effect until it is acknowledged by the Commission.

B. Schedule and Filing

1. By April 1 of every third year, each load-serving entity shall submit for Commission acknowledgment an IRP proposal in accordance with the provisions of this Article and applicable Commission resolutions and orders. In the case of a substantial change in the energy demand or group of resources, the Commission may order that the review of the next IRP be carried out before the three (3) years provided here to respond to and/or mitigate such changes. At any moment prior to the three-year filing requirement, a load-serving entity may submit a proposed update, amendment or review to an acknowledged IRP, as described in Section R14-2-708.
2. The filing of the IRP shall initiate a proceeding at the Commission pursuant to the provisions of this Article.

C. Integrated Resource Plan Filing Structure and Requirements

1. The IRP filing shall be comprised of a main body and accompanying technical appendices.
   a. The main body of the IRP shall be written as a coherent, stand-alone document designed to allow informed readers sufficient information to understand the process by which a load-serving entity conducts long-term resource planning and the key outcomes of that resource planning. The main body shall be organized into the following chapters:
      Part One – Introduction and Summary of Conclusions
      Part Two – Planning Environment
      Part Three – Load Forecast
      Part Four – Existing Resources
      Part Five – Resource Needs Assessment
      Part Six – New Resource Options
      Part Seven – Assumptions and Forecast
      Part Eight – Resource Plan Development
      Part Nine – Caveats and Limitations
      Part Ten – Work Plan
      Part Eleven – Action Plan
      Part Twelve – Other considerations or additional information, as required by the Commission through and order, that may address subjects related to integrated resource planning.
   b. The technical appendices of the IRP filing shall include ancillary information and descriptions required by this Article but not included in the main body of the IRP filing. The following technical appendices must be attached to the IRP filing:
      Appendix 1 – Transmission and Distribution Planning
      Appendix 2 – Prior Action Plan Implementation Status
      Appendix 3 – Renewable Energy Project Status
      Appendix 4 – Demand-Side Resources
      Appendix 5 – New and Existing Supply-Side Resource Supplemental Data
      Appendix 6 – Additional information, as required by the Commission through and order, that may address subjects related to integrated resource planning.
   c. The IRP filing shall specifically identify and include all references to external and internal source documents relied upon in the development of the proposed IRP.
      1. If a source document is publicly available on the Internet, a specific link (URL address) to the source document shall be provided.
      2. If a source document referenced by the load-serving entity in any portion of its IRP filing is not publicly available or readily accessible, an electronic copy of such source documents shall be provided along with the IRP filing.
      3. If a source document consists of a study, report, book, periodical, or other publication, not publicly available or readily accessible, the load-serving entity shall provide copies of the relevant pages from such source documents relied upon in the development of its proposed IRP. All pages which are necessary to understand the relevant pages in context shall be provided. Upon request, the load-serving entity shall make available the entirety of such source document. In the case such source documents are protected under federal copyright law, the load-serving entity shall make a reference to the documents used for the development of the proposed IRP.
   d. Work papers and models relied upon by the load-serving entity in the development of the IRP shall be filed concurrently with the IRP.
      1. Work papers which are available in electronic form shall be provided electronically in native format. All formulae and viable links shall be left intact.
      2. The load-serving entity shall, at a minimum, provide the following work papers to the Commission:
         i. Load Forecast Development work papers;
         ii. Fuel Price Forecast Development work papers;
         iii. Resource Plan modeling input files;

iv. Resource Plan modeling output files as used by the load-serving entity;
v. Any post-processing or analysis work papers used to assess the Resource Plan modeling output files, including financial models used to calculate the present value of revenue requirements, rate impacts, or other cost elements of the IRP;
vi. Electronic, spreadsheet-based versions of all tables and figures as presented in the IRP.

e. The load-serving entity shall provide access to the modeling software, including license to Staff of the model(s) they use, at a minimum, and to provide, as an addendum to the filing, inputs and outputs and/or saved run files from the models. Such access shall be adequate to enable the Commission to replicate the results and may include the load-serving entity manipulating the computer model according to instructions or input from the Commission. Reasonable access shall also be provided to intervenors. If the load-serving entity seeks to limit access to the program or application to intervenors, the Commission will determine the appropriate access to the program or its output.

f. The load-serving entity shall use modeling software that meets the following criteria:
1. There are no technical or legal barriers to providing inputs and outputs of the model to stakeholders in a format legible to stakeholders;
2. The utility can provide the modeling parameters to stakeholders;
3. The software can reasonably model all types of resources, including wind, solar, and storage, including battery storage;
4. The software can model at hourly and sub-hourly timescales; and
5. The software is capable of modeling fixed resource retirement dates or optimizing resource retirement dates.

2. When filing its IRP, the load-serving entity shall simultaneously publish its IRPs in its full and complete form on the utility's website, which should be presented in an accessible and comprehensible way to the general public. The load-serving entity may only withhold information from reporting with Commission approval, under a protective order as provided in Section R14-2-707(D)(3), and stakeholders shall have a reasonable opportunity to challenge designations of information as confidential.

R14-2-706. Integrated Resource Plan Requirements

A load-serving entity shall, by April 1 of every third year, file with Docket Control a preliminary IRP. Consistent with Section R14-2-705(C) above, a load-serving entity's IRP must include the following:

A. Planning Environment: The IRP shall include a description of the various current laws, regulations, and other rules that might affect planning decisions, as well as any that are likely to be implemented during the course of the planning period.
1. This section shall describe, at a minimum, the following factors: federal, state, or municipal standards and rules that impact the requirement for, or availability of, energy efficiency, renewable energy, fuel alternatives, or other resource requirements; and environmental standards and regulations that impact existing utility resources or resource choices at the present time through the planning period.
2. This section shall also include a discussion of substantial regulatory or legislative standards and rules that have changed since the acknowledgment of the most recent IRP.

B. Load Forecast: The load-serving entity shall provide a compilation of peak electricity demand and annual electricity consumption forecasts for each year of the IRP planning period which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing.
1. The load forecasts will include the following items:
   a. Fifteen-year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses;
   b. The load-serving entity shall prepare at least three (3) baseline Load Forecasts to reflect a reasonable range of future uncertainties:
      1. A reference case representing the load-serving entity's best understanding of expected circumstances or median probability outcomes;
      2. A low case where customer electricity demand and consumption are significantly below utility median expectations through the planning period; and
      3. A high case where customer electricity demand and consumption are significantly above utility median expectations through the planning period.
   c. Disaggregation of the load forecast into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures;
   d. Analysis and consideration of the impact of:
      1. Existing demand-side resources, anticipated changes to rate design, building codes and standards, deployment of distributed generation, and other important factors on the load forecast;
      2. Technical losses in the load forecast, including the extent to which the forecast includes the effects of current and planned technical loss reduction programs; and
      3. Non-technical losses in the load forecast, including the extent to which the forecast includes the effects of current and planned non-technical loss reduction programs.

e. Historic peak demand and energy. Historic data shall be reported covering a ten (10)-year period prior to the first year of the IRP Planning Period and shall include:
   1. The total annual electricity generation and sales for the utility and consumption for each customer class; and
   2. The coincident peak electricity demand for the utility and each customer class.

f. Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.

g. An evaluation of prior load forecasts provided in the most recent IRP, including:
   1. Assessment of the annual accuracy of the previous forecasting including a comparison of forecasted versus actual data;
   2. An explanation of the cause of any significant deviation (meaning more than 5%) between the previous forecasts and the actual annual peak demand and energy that occurred; and
   3. An explanation of the impact that historic demand-side resources had on the prior load forecast.

2. The load forecasts will be conducted in accordance with the following criteria:
   a. A reasonable set of assumptions for economic and/or end use variables shall be included in the development of the long-term load forecasts.
   b. The load forecasts shall reflect normal weather conditions but must account for forecasted changes in climate due to climate change.

C. Existing Resources: The load-serving entity shall describe all existing resources that serve or meet the entity's customer's energy and capacity requirements. The IRP shall include the following, which may include references to data reported under Section R14-2-704 above:

1. A description of all demand-side resources currently being implemented by or on behalf of the load-serving entity.
2. A description of the energy supply from existing supply-side resources.
   a. This section shall describe each type of supply-side resources, and including at least the following categories:
      1. Utility-owned generation;
      2. Wholesale power purchase transactions that are one (1) year or longer and a detailed discussion of the transaction, including the term of the contract, expiration date, pricing provisions, source of the power, fuel source, and other relevant information;
      3. Cogeneration and small power production;
      4. Distributed generation;
      5. Pooling or coordination agreements that reduce resource requirements; and
      6. Any other supply-side resources.
   b. In addition, the following information concerning each existing supply-side resource shall be supplied, as applicable and as readily available to the load-serving entity with respect to third-party resources, in the form of a coherent table(s) in the body of the IRP:
      1. Resource type;
      2. Nameplate and peak available capacity;
      3. Annual capacity factor for each of the last five (5) years;
      4. Fuel type;
      5. Ownership information, including the portion of the resource owned by the load-serving entity, by a private project developer, or by a customer;
      6. Location (district or municipality);
      7. Commercial operation date;
      8. Remaining service life;
      9. Any anticipated projects or programs that would alter remaining service life;
      10. Remaining contract life, including capacity contracts;
      11. Depreciation schedule;
      12. Other contracts that need to be renegotiated (e.g., for water, land lease, fuel supply);
      13. Average annual heat rate over the last five (5) years;
      14. Current fuel cost in dollars per MMBtu;
      15. Current variable operations and maintenance (O&M) cost in dollars per MWh;
      16. Current total production cost in dollars per MWh, including any other necessary variables aside from fuel and variable O&M costs;
      17. Anticipated total production cost in dollars per MWh, including any other necessary variables aside from fuel and variable O&M costs, for future years through the planning period;
      18. Current fixed O&M cost in dollars per kW;
      19. Average annual capital expenditures over the last five (5) years in total dollars; and
      20. Average annual water consumption, source of supplied water.
   c. This section shall also include an assessment of potential cost-effective retirements of all utility-owned resources including the costs associated with incremental depreciation expenses and estimated operational and capital savings.
      1. For each retirement reviewed, the load-serving entity shall:

i. Describe the replacement resource need, possible system reliability impacts, and corrective actions for such impacts; and
ii. Evaluate at least one retirement date that is within the resource acquisition period.

2. If discontinuation, decommissioning, or mothballing of any power source or permanent derating of any generating facility is expected, the load-serving entity shall provide:
   i. Identification of each power source or generating unit involved;
   ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating;
   iii. The reasons for each discontinuation, decommissioning, mothballing, or derating.
3. For the purpose of identifying existing resources that potentially are not cost-effective as compared to other resources available in the market, the load-serving entity shall compare the costs and performance of each of its existing resources (utility-owned and contracted) to the costs and performance of generic resources, including energy efficiency and demand response alternatives. The load-serving entity shall also conduct computer modeling that, at a minimum, evaluates retirement of each existing generating unit, and retirement of combinations of existing generating units, under a reasonable range of scenarios during the resource acquisition period. The load-serving entity need not model retirement of an existing generating unit if a screening analysis shows the unit to be clearly economic compared to replacement resources.

d. The following information concerning each existing supply-side resource shall be supplied as part of Appendix 5:
   1. All information in sub-section (b) above;
   2. Dates for renewal of operating licenses and permits, to the extent applicable;
   3. Compliance schedule with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;
   4. Expected capital and operating costs for compliance with current, proposed, and reasonably anticipated regulatory (including environmental regulatory) and legal requirements, to the extent applicable;
   5. Expected yearly non-environmental capital expenditures for the first ten (10) years of the Planning Period, including any improvements to operational efficiencies or extensions of the useful life;
   6. Any important changes to the resources that occurred since the acknowledgment of the most recent IRP or which is expected to occur prior to the filing of a review, update, or amendment, including:
      i. A description of each large capital project (over $5,000,000) expected in the next five (5) years;
      ii. Changes in fuel types expected to result from economic restrictions or environmental regulations.

D. Resource Needs Assessment: The load-serving entity shall prepare a resource needs assessment and a detailed description of the results of such assessment. The purpose of the resource needs assessment is to identify current and/or future expected capacity and/or energy requirements resulting from the expected or contractual retirement of, or cessation of services from, existing supply and demand-side resources when compared against forecast load conditions. The resource needs assessment shall contain at least the following elements:

1. An expected planning reserve margin over a fifteen-year period.
   a. The planning reserve margin shall follow industry standard methodologies in assessing a necessary planning reserve margin to maintain reliable service during the planning period.
   b. To the extent that the reserve margin assessment cannot be developed independently of a resource plan, the load-serving entity may use its then-current business plan to assess and describe the necessary planning reserve margin.
   c. The load-serving entity shall demonstrate why the planning reserve margin targets in its forecast are reasonable.
2. A coherent table showing, by year, the expected capacity of each existing supply-side and existing demand-side resource, its load requirements, and load requirements including the planning reserve margin. The load-serving entity shall identify its annual net position relative to its expected needs throughout the planning period.
   a. The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period; and
   b. An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona.

E. New Source Options: The load-serving entity shall assess the need for its existing resources and any need to acquire new resource options that may reasonably serve or meet the load-serving entity's customer's energy and/or capacity requirements.

1. The IRP shall identify and evaluate a wide range of new supply-side resource options, including renewable and non-renewable options, to be used in the development of the IRP. While a load-serving entity may designate specific options as not feasible for future development, such designations must be accompanied by a clear and comprehensive explanation that justifies the load-serving entity's determination on the basis of cost, resource availability, or engineering feasibility.
   a. For each supply-side resource option identified as a feasible alternative, the load-serving entity shall provide the following information, as applicable, in the form of a coherent table in the body of the IRP:
      1. Resource type;
      2. Location, if a specific project site has been identified; otherwise, restrictions and other considerations that may dictate resource placement;
      3. Capacity;
      4. Fuel type;

5. Capacity factor for renewable energy resources;
6. Effective load carrying capacity (ELCC) or capacity contribution to peak;
7. Ownership information, including the portion of the resource owned by the load-serving entity, by a private project developer, or by a customer;
8. Anticipated service life;
9. Heat rate;
10. Overnight capital cost;
11. Fixed operations and maintenance cost;
12. Non-fuel variable operations and maintenance cost; and
13. Average annual water consumption.

b. For each resource identified in subsection (a) above, the following additional information shall be supplied:
1. All information in (a) above;
2. Other costs to construct and/or operate the resource, including financing costs, property taxes, supplemental payments, and interconnection costs;
3. Lead time necessary to plan and build, or acquire through a power purchase agreement;
4. Any constraints on the acquisition or construction of the resource as applied by the load-serving utility in the capacity expansion model, including first potential date of construction, maximum units feasible to acquire or construct per year, and total number of the resources allowed in the model through the planning period;
5. Any constraints on the operation or dispatch of the resource as applied by the load-serving entity in its modeling, including minimum up-time, minimum down-time, or energy or effluent limitations;
6. Any impact of the location of the resource on reliability and system resilience;
7. Evaluation of the interconnection of renewable energy projects and independent power producers to the utility system; and
8. A description, with quantitative information and analysis as required, of how the resource contributes to meeting the requirements of the Clean and Renewable Energy Standard in Article 18 of this Chapter.

2. The IRP shall include a projection and account for expected types and amounts of customer-owned distributed generation, by customer class, including:
a. A 15-year forecast of self generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);
b. Disaggregation of the forecast of subsection (B) into two components, one reflecting the self generation projected if no additional efforts are made to encourage self generation, and one reflecting the self generation projected to result from the load-serving entity's institution of additional forecasted self generation measures;
c. A 15-year forecast of the annual capital costs and operating and maintenance costs of the self generation identified; and
d. Documentation of the analysis of the self generation;

3. This section shall also include the following:
a. A calculation of the benefits of generation using renewable energy resources;
b. Analysis of integration costs for intermittent resources;
c. A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;
d. A description of a wide range of potential new energy efficiency and demand response programs.
1. For each demand management program or measure, the IRP will describe:
i. How and when the program or measure will be implemented;
ii. The projected participation level by customer class for the program or measure;
iii. The expected change in peak demand and energy consumption resulting from the program or measure;
iv. The expected reductions in environmental impacts, including air emissions, solid waste, and water consumption, attributable to the program or measure;
v. The expected societal benefits, societal costs, and cost-effectiveness of the program or measure;
vi. The expected life of the measure; and
vii. The capital costs, operating costs, and maintenance costs of the measure, and the program costs;
2. For each demand management measure that was considered but rejected:
i. A description of the measure;
ii. The estimated change in peak demand and energy consumption from the measure;
iii. The estimated cost-effectiveness of the measure;
iv. The capital costs, operating costs, and maintenance costs of the measure, and the program costs; and
v. The reasons for rejecting the measure.

e. A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and for reducing water consumption.

F. Assumptions and Forecasts

1. The IRP shall document key modeling assumptions and inputs including, at least, the following:
a. Annual fuel prices for each delivered fuel;
b. Annual emission prices;
c. Economic conditions;
d. Environmental regulations;

e. Other non-environmental regulations, including renewable portfolio standards;
f. Utility discount rate or weighted average cost of capital;
g. Annual debt limitations.

2. The IRP shall also identify factors that will significantly influence key forecasts (including electricity demand, electricity consumption, fuel prices), and develop a range of possible outcomes for those forecasts encompassing at least the fifth (5th) and ninety-fifth (95th) percentile outcomes as understood by the load-serving entity.
   a. Forecasts should include exogenous elements beyond the load-serving entity's control, including but not limited to:
      1. Economic conditions;
      2. Environmental regulations;
      3. Changes in customer load not caused by utility demand-side resources;
      4. Customer-sited distributed generation;
      5. Fuel prices;
      6. Emissions costs; and
      7. Capital costs.
   b. For each forecast, the IRP shall identify a reference case forecast, and describe the basis of the forecast range identified.
   c. The IRP shall consider multiple scenarios that encompass the reasonable range of possible outcomes for uncertain forecasts. Scenarios may combine key forecasts in a manner that enables a reasonable exploration of the range of foreseeable risks to the safety, reliability, and affordability of retail services. The IRP shall consider a sufficient number of scenarios to both describe feasible or likely sets of forecasts, as well as capture a wide range of possible risks.
      1. The load-serving utility shall justify the scenarios used and excluded from consideration and describe why the combinations assessed represent a reasonable range of risks.
      2. To the extent that the load-serving entity relies on explicit or implicit relationships or correlations between forecasts, the load-serving entity shall describe the basis of the relationships.
      3. The load-serving entity shall incorporate any scenarios required by the Commission or reasonably suggested by interested stakeholders.
   d. The IRP shall include a Reference Case Scenario, representing the load-serving entity's best understanding of expected circumstances or median probability outcomes.

G. Resource Plan Development.

1. The IRP shall identify in detail the mechanisms used by the load-serving entity in developing its resource plans.
   a. The IRP shall include, within the main body of the IRP, the following:
      1. Comprehensive descriptions of the modeling mechanisms used in the development and sensitivity analysis of each resource plan, based on Capacity Expansion Models. The load-serving entity may in addition use production cost models, a heuristic approach, or a combination of the two.
      2. Descriptions of key resource plan assumptions and purposes, including consideration of stakeholder input and Commission requirements;
      3. A coherent table illustrating the key difference between resource plans, including annual retirements, retrofits or conversions, and new builds for both supply- and demand-side resources, changes in capacity (uprates or derations) or existing supply- and demand-side resources, changes in transmission or distribution systems, key assumptions, and resource plan cost;
      4. A description of the mechanism and criteria used to select the Preferred Resource Plan, following the requirements of subsection (2)(c) below;
      5. A coherent load and resource balance table for the Preferred Resource Plan showing, by year, the expected capacity of each existing and new supply-side and demand-side resource, its expected peak load, its planning reserve margin, and its total load requirements, including the planning reserve margin. The load-serving entity shall identify its annual net position relative to its expected needs during the planning period.
      6. For the Preferred Resource Plan, and for each resource plan considered in the IRP, the IRP shall include, at a minimum, the following supplemental information:
         i. A table of annual capacity contribution by resource;
         ii. A table of annual generation by resource;
         iii. A table of annual emissions by resource;
         iv. A table of annual fuel consumption by fuel type;
         v. A cash-flow table comprised of annual cost values for, at a minimum, fuel spending by type of fuel, generation capital, transmission capital, fuel infrastructure capital, total generating unit variable operations and maintenance, total generating unit fixed operations and maintenance, fuel infrastructure operations and maintenance, CO2, NOx, SO2 emissions, water consumption, fossil fuel power purchase agreements; and renewable power purchase agreements.

2. Resource Plan Development Analysis
   a. The IRP shall use a Capacity Expansion Model to develop least-cost resource plans that meet customer needs under the reference case scenario and various future scenarios. If the load-serving entity does not use a Capacity Expansion Model to develop least-cost resource plans, the load-serving entity must seek, and receive, a waiver from the Commission to use any other kind of resource plan development model for this purpose, in which case the Commission may adopt through

resolution any and all appropriate requirements to ensure reliability of the information and conclusions produced and presented in the IRP.

1. The Capacity Expansion Model shall, at a minimum:
   i. Seek to optimize the present value of revenue requirements over the planning period;
   ii. Consider demand-side resources in a competitive framework with supply-side resources;
   iii. Recognize all utility-borne costs associated with the development of new resources;
   iv. Recognize all utility-borne costs, as well as avoided costs, associated with the retirement or modification of existing resources.
2. Costs that the load-serving entity has incurred or committed prior to the commencement of the planning period (including, but not limited to, existing plant balances, committed capital expenditures, and rate-based costs) shall not be assessed in the Capacity Expansion Model unless they are specifically avoidable through the procurement of new assets or retirement or modification of existing assets.
3. The load-serving entity shall use the Capacity Expansion Model to develop a comprehensive set of resource plans to include a wide variety of supply-side, energy efficiency, and demand response resources.
4. Supply-side resources shall include various options for early retirement of existing power plants, for refurbishment or repowering of existing power plants, and for deferral of new power plants where feasible.
5. Supply-side resources shall also include any changes in the transmission or distribution systems that accompany generation resources or are necessary for the maintenance of system reliability.
6. Energy efficiency and demand response resources shall include programs with a variety of different cost levels, in order to assist in the identification of all cost-effective energy and demand respond resources.
7. The load-serving entity shall incorporate any resource plans required by the Commission.
8. The load-serving entity shall provide a comprehensive discussion of any resource plans excluded from consideration on the basis of reliability or viability.
9. Each resource plan shall be designed to ensure that the load-serving entity complies with the Clean and Renewable Energy Standard requirements of Article 18 of this Chapter.

b. Each of the resource plans resulting from the Resource Plan Development Modeling shall be subjected to sensitivity analyses exploring a reasonable range of uncertainty in forecast assumptions. The purpose is to examine the robustness of resource plans created in the optimization analysis (i.e., how each plan affected by changes in the input assumptions). To that end, the IRP shall include a compilation of the following analyses and plans:
   1. Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:
      i. Demand forecasts;
      ii. The costs of demand management measures and power supply;
      iii. The availability of sources of power;
      iv. The costs of compliance with existing and expected environmental regulations;
      v. Any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations;
      vi. Changes in fuel prices and availability;
      vii. Construction costs, capital costs, and operating costs; and
      viii. Other factors the load-serving entity wishes to consider;
   2. A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (b)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects; and
   3. A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (b)(1).

c. The load-serving entity shall select a Preferred Resource Plan from among the resource plans developed and evaluated in the optimization and sensitivity analyses.
   1. In selecting the Preferred Resource Plan, the load-serving entity shall use the minimization of the present value of revenue requirements as the primary selection criterion.
      2. The load-serving entity shall also consider other criteria, including but not limited to, system reliability; short- and long-term risk; environmental impacts; transmission needs and implications; distribution needs and implications; financial impacts on the load-serving entities; opportunities to site renewable facilities in communities where conventional generation has been retired; and the public interest. Where meeting these needs is associated with quantifiable costs, these costs shall be included in the calculation of the present value of revenue requirements.
   3. The IRP shall include detailed discussion of each of the above factors in support of its Preferred Resource Plan. The load-serving entity may opt to choose a plan that is not the lowest cost, provided that, in doing so, it presents a detailed description of all the criteria and reasoning used to select the Preferred Resource Plan that is not the lowest cost.

H. Caveats and Limitations: The IRP shall include an annotated list of key caveats and limitations of its analysis, including the impact of uncertainty, the modeling mechanism, key regulatory and project execution assumptions, and costs. The purpose of this section is to illustrate the load-serving entity's certainty with respect to the Preferred Resource Plan.

I. Work Plan: No more than two (2) years following a load-serving entity's most recently-submitted IRP, the load-serving entity shall file with Docket Control a work plan that includes:

1. An outline of the contents of the IRP the load-serving entity is developing to be filed the following year as required under Section R14-2-705(B);
2. The load-serving entity's method for assessing potential resources;
3. The sources of the load-serving entity's current assumptions and a plan to incorporate forecasts based on inputs suggested by stakeholders; and
4. An outline of how the load-serving entity plans to ensure significant stakeholder engagement, including the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan.
   a. The load-serving entity must provide for at least four meetings with stakeholders during the IRP development process for the following purposes:
      1. At the beginning, to collaborate on the planning approach, priorities, and evaluation criteria;
      2. Prior to extensive analysis, to discuss model input assumptions and analysis structure;
      3. Post-analysis, to discuss the results and draw conclusions about the import of those results; and
      4. After a final draft IRP has been developed, to present findings and the resulting actions before it is filed with ACC.
   b. The load-serving entity may provide additional meetings depending on the level of interest from stakeholders.
   c. In order to make these meetings effective, stakeholders must have access to the pertinent data, including modeling inputs and assumptions, if necessary under a reasonable non-disclosure agreement or protective order that effectively balances the public's right to access information with the utility's interest in limiting access to confidential business information, and the utilities should be prepared with the appropriate personnel and experts to answer questions. Throughout the stakeholder engagement process, the load-serving entity must, at a minimum:
      1. Solicit alternative modeling inputs/parameters for alternative modeling runs; and
      2. Respond to requested alternatives by either performing the runs or explaining why they chose not to perform the requested runs.
   d. Following each meeting, the load-serving entity shall provide meetings minutes, or if possible a recording, for future reference by stakeholders and to ensure that the utility has future access to all relevant information or concerns raised during the meetings. Such minutes or recording must provide enough information to make clear who (either which individual or organization) presented any given idea or suggestion during a meeting.
   e. The work plan shall describe and demonstrate that the stakeholder engagement process has been satisfied and will continue to be met throughout the IRP process;

J. Action Plan: With its IRP, a load-serving entity shall include an action plan, based on the results of the resource planning process.

1. The purpose of the action plan is to specify implementation actions that need to be performed during the first five years of the planning period as a result of the Preferred Resource Plan. The action plan is not intended to replace or modify additional resource certification processes required by statute or other Commission rules and orders.
2. The action plan shall include, at a minimum:
   a. Details on the intent and specific markers required to meet the load-serving entity's specific needs over the first five years of the planning period.
      1. The action plan shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral.
      2. The purpose of the action plan is to facilitate in a subsequent all-source RFP consideration of demand-side resources on equal footing as supply-side ones and must not be limited to "dispatchable" resources.
   b. A summary of actions on treatment of existing resources or future resource acquisitions that the load-serving entity believes may satisfy its defined future needs based on the Preferred Resource Plan. This should include a table of key actions in the first five years after acknowledgment of the IRP including, at a minimum, expected procurement processes for supply-side resources and energy efficiency, permitting requirements, construction activities, required studies, and other significant events. Although such summary and table shall provide the load-serving entity's suggestions for specific actions, the load-serving entity shall base its selection of specific resources on the results of an all-source RFP to satisfy the needs identified in subsection (a) above.
      1. The action plan shall cover intended acquisitions of demand-side, supply-side, transmission, distribution, and/or fuel infrastructure resources; retirements and/or retrofits of existing generating resources; entrance into, renegotiation or cessation of power purchase agreements; and any other resource commitments.
      2. For each action identified in the action plan, the IRP shall specify and provide:
         i. The expected calendar year and quarter in which the action will be commenced;
         ii. The expected calendar year and quarter in which the action will be completed;
         iii. Issuances of permits and other regulatory actions that are required in order for the action to take place;
         iv. For any major expected resource acquisitions, retirements, retrofits, or power purchase agreements, the action plan shall provide information on the cost of the option chosen and the plan for financing that option;

v. The anticipated impact of the action on any relevant performance metrics established by the Commission; and

vi. Any other information required by the Commission through resolution or order.

3. The action plan shall cover the five-year period following the Commission's acknowledgment of the resource plan. Any given action plan will remain in effect until a new action plan is approved as part of a subsequent IRP proceeding or until the Commission states otherwise.

4. The IRP shall provide a status update on the implementation of the action plan in effect at the time of the filing of the IRP (or the most recent action plan, if the filing of a proposed IRP occurs after the expiration of any previous action plan). This status update shall include the following:

   a. An itemized list of each element of the prior IRP action plan;
   b. A description of the load-serving entity's actions taken to execute each action item;
   c. Any changes to date in the timeframe of expected commencement and completion, permitting or regulatory requirements, or removal of the action item based on intervening events;
   d. Any changes to permitting, engineering, or construction processes of major projects already in progress; and
   e. A description of the cause of any changes to the prior IRP action plan.

5. The action plan shall also provide an explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided costs shall include, but is not limited to, the following:

   a. The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement;
   b. The avoided transmission capacity cost;
   c. The avoided distribution capacity cost: and
   d. The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.

R14-2-707. Commission Review and Acknowledgement of Load-serving Entity Integrated Resource Plans

A. IRP Prefiling Process

1. At least one year before the next IRP is due, the Commission may schedule one or more technical conferences to gather information regarding the methodology and contents contemplated by the load-serving entity for its new IRP proposal.

   a. In scheduling these technical conferences, the Commission may require a load-serving entity to provide specific information regarding the development of the proposed IRP.
   b. The Commission will set forth, in its orders scheduling the technical conferences, the process for the orderly presentation of the information.
   c. The purpose of these technical conferences is to provide an opportunity for the Commission to ensure a load-serving entity's IRP filing will reasonably comply with the requirements set forth in this Regulation and the analysis conducted therein will be sufficiently robust so as to comply with public policy goals and meet Commission expectations as to the quality of the analysis and information provided. These proceedings will also provide an opportunity for the load-serving entity to seek clarifications from the Commission with regards to compliance with the requirements set forth in this Regulation.
   d. The Commission may require a load-serving entity to address any issues it believes should be included in the IRP that are not specifically set forth in these rules.

2. The load-serving entity shall, before setting assumptions on cost of particular resources, conduct an all-source Request for Information (RFI), wherein the utility solicits open all-source bids for new energy, capacity, and grid services from market participants.

   a. The resulting bids shall form a cohort of known new resource options with appropriate pricing and availability that shall be used to inform assumptions and the evaluation of resources within the IRP.
   b. The RFI shall identify the specific needs to be satisfied, but it must be technology neutral, location neutral, and size neutral. The RFI shall consider demand-side resources one equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

1. **B. Review by Staff** Within three (3) months of the submission of a preliminary IRP, Staff shall file a report that contains its analysis and conclusions regarding its statewide review and assessments of the load-serving entity's IRP.

2. If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff shall request additional information from the load-serving entity, including the data used in the load-serving entity's analyses.

3. Staff may request that a load-serving entity complete additional analyses to improve specified components of the load-serving entity's submissions and may request a technical conference with the load-serving in order to gather information regarding the methodology and contents contemplated by the utility so that the Commission can assess the quality and robustness of the utility's analysis.

C. Review by Commission: Within 9 months of the filing of a preliminary IRP, the Commission shall issue an order making the following specific findings:

1. **Completion:** The Commission shall determine whether the IRP is adequate as an informational document to allow full and robust review by stakeholders and the ACC and to facilitate consideration of the load-serving entity's resource alternatives. If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff or the Commission shall request additional information from the load-serving entity, including the

data used in the load-serving entity's analyses. A determination of completeness or sufficiency as an informational document shall not be construed as a ruling on the substance of the IRP.

2. **Acknowledgement:** The Commission shall issue an order acknowledging, rejecting, or modifying a load-serving entity's IRP in whole or in part. The Commission will acknowledge components of the IRP if the Commission determines that the IRP, as amended if applicable, complies with the requirements of this Article and that the load-serving entity's IRP is reasonable and in the public interest, based on the information available to the Commission at the time and considering the following factors:
    a. The IRP sufficiently analyzed the components provided under Section R14-2-706;
    b. The total cost of electric energy services (the IRP should provide least-cost service);
    c. The degree to which the factors that affect demand, including demand management, have been taken into account;
    d. The degree to which the IRP will minimize, to the extent practicable, adverse socioeconomic and environmental effects;
    e. The degree to which the IRP will enhance the utility's ability to respond to financial, social, and technological changes affecting its operations;
    f. The degree to which supply alternatives, such as self generation, have been taken into account;
    g. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the load-serving entity to respond to unforeseen changes in supply and demand factors;
    h. The reliability of power supplies, including fuel diversity and non-cost considerations;
    i. The reliability of the transmission grid;
    j. The degree to which the IRP will limit the risk of adverse effects on the utility and its customers from factors outside of the utility's control;
    k. The environmental impacts of resource choices and alternatives;
    l. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;
    m. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers; and
    n. The degree to which the load-serving entity's IRP allows for coordinated efforts with other load-serving entities.
3. A load-serving entity may seek Commission approval of specific resource planning actions.

D. Procedure Before the Commission

1. **Hearing:** The Commission may hold a hearing or workshop regarding a load-serving entity's IRP. If the Commission holds such a hearing or workshop, the Commission may extend the deadline for the Commission to issue an order regarding acknowledgment under subsection (C). Any public hearing shall be on the record and a transcript shall be made publicly available for future reference by stakeholders and the load-serving entity.
2. **Discovery:** The Commission shall permit reasonable discovery by interested stakeholders during the prefiling process, after an IRP is filed, and during the hearing in order to assist parties and interested persons in obtaining evidence concerning the integrated resource plan, including, but not limited to, the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties. Data protected by a protective order shall not be submitted to Docket Control and will not be open to public inspection or otherwise made public except upon an order of the Commission entered after written notice to the load-serving entity. Interested stakeholders shall have the opportunity to agree to reasonable terms of a protective order in order to gain access to protected information.
3. **Confidentiality and Protective Orders:** If a load-serving entity believes that a data-reporting requirement may result in disclosure of confidential business data or confidential electricity infrastructure information, the load-serving entity may submit to Staff a request that the data be submitted to Staff under a protective order, which request shall include an explanation justifying the confidential treatment of the data.
4. **Supplemental Information:** A load-serving entity or interested party may provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops. Similarly, if comments from interested stakeholders indicate additional information is appropriate, Staff or the Commission may request such information from the load-serving entity.
5. **Effect of Commission Acknowledgment:** While no particular future ratemaking treatment is implied by or shall be inferred from the Commission's acknowledgment, the Commission shall consider a load-serving entity's filings made under R14-2-706 when the Commission evaluates the performance of the load-serving entity in subsequent rate cases and other proceedings. Although decisions regarding whether to allow a utility to recover from its customers the costs associated with new resources may only be made in a rate case proceeding, acknowledgment of an IRP is relevant to subsequent examination of whether a utility s resource investment is prudent and should be recovered from ratepayers. Just as acknowledgement does not guarantee favorable ratemaking, a decision to not acknowledge an action item does not constitute a preliminary determination of impudence. The Commission can nevertheless consider whether a load-serving entity has proceeded with an expenditure that has either been expressly rejected or otherwise not acknowledged by the Commission when evaluating the performance of the load-serving entity in a subsequent rate case.

R14-2-708. Update, Amendment, or Review to an Acknowledged IRPA load-serving entity may file an amendment to an acknowledged IRP if changes in conditions or assumptions necessitate a material change in the load-serving entity's plan before the next IRP is due to be filed. As soon as the load-serving entity anticipates a significant deviation from its acknowledged IRP, it must file an update / amendment with the Commission unless the load-serving entity is within six months of filing its next IRP. This filing must meet the requirements set forth in Section R14-2-706 of this rule.

A. Reasons that might warrant a load-serving entity to consider proposing an update / amendment include, but are not limited to:

1. It anticipates submitting an application for a certificate to construct, purchase, or otherwise acquire a long-term supply-side or demand-side resource that was not previously included as part of the current acknowledged IRP;
2. It anticipates the need to undertake a procurement process for a demand-side or supply-side resource that was not included as part of the current acknowledged IRP;
3. It expects to make a Major Change to the IRP or the Action Plan before the filing of the next IRP proposal.

B. Notwithstanding paragraph (A), the Commission shall have the authority to require a load-serving entity to file an update, amendment, or review to the acknowledged IRP, should it determine that conditions warrant such action.

C. If the load-serving entity requests Commission acknowledgement of proposed changes to the action plan contained in its acknowledged IRP:

1. The load-serving entity must file its proposed changes with the Commission and present the results of its proposed changes to the Commission at a public meeting prior to the deadline for written public comment; and
2. Commission staff and parties must file any comments and recommendations with the Commission and present such comments and recommendations to the Commission at a public meeting within six months of the load-serving entity's filing of its request for acknowledgement of proposed changes; and
3. The Commission may provide direction to an energy utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

D. The filing of an IRP update does not relieve a load-serving entity from its obligation to file a new, complete IRP every three (3) years.

R14-2-709. Procurement

A. Except as provided in subsection (B), a load-serving entity may use the following procurement methods for the wholesale acquisition of energy, capacity, and physical power hedge transactions:

1. Purchase through a third-party online trading system;
2. Purchase from a third-party independent energy broker;
3. Purchase from a non-affiliated entity through auction or an RFP process;
4. Bilateral contract with a non-affiliated entity;
5. Bilateral contract with an affiliated entity, provided that non-affiliated entities were provided notice and an opportunity to compete against the affiliated entity's proposal before the transaction was executed; and
6. Any other competitive procurement process approved by the Commission.

B. Any RFP shall seek to satisfy a load-serving entity's basic needs, as defined in the action plan, rather than define a specific technology or source. As such, an RFP shall be technology neutral, location neutral (any unit that can deliver energy/capacity into the particular zone even if not located there should be permitted to compete), except that preference shall be given to renewable resources sited in communities where conventional generation has been retired, and size neutral. The RFP shall consider demand-side resources one equal footing as supply-side ones and shall not be limited to "dispatchable" resources.

C. A load-serving entity shall use an RFP process as its primary acquisition process for the wholesale acquisition of energy and capacity, unless one of the following exceptions applies:

1. The load-serving entity is experiencing an emergency;
2. The load-serving entity needs to make a short-term acquisition to maintain system reliability;
3. The load-serving entity needs to acquire other components of energy procurement, such as fuel, fuel transportation, and transmission projects;
4. The load-serving entity's planning horizon is two years or less;
5. The transaction presents the load-serving entity a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, compared to the cost of acquiring new generating facilities, and will provide unique value to the load-serving entity's customers;
6. The transaction is necessary for the load-serving entity to satisfy an obligation under the Renewable Energy Standard rules; or
7. The transaction is necessary for the load-serving entity's demand-side management or demand response programs.

D. A load-serving entity shall engage an independent monitor to oversee all RFP processes for procurement of new resources.

R14-2-7010. Independent Monitor Selection and Responsibilities

A. When a load-serving entity contemplates engaging in an RFP process, the load-serving entity shall consult with Staff regarding the identity of companies or consultants that could serve as independent monitor for the RFP process.

B. After consulting with Staff, a load-serving entity shall create a vendor list of three to five candidates to serve as independent monitor and shall file the vendor list with Docket Control to allow interested persons time to review and file objections to the vendor list.

C. An interested person shall file with Docket Control, within 30 days after a vendor list is filed with Docket Control, any objection that the interested person may have to a candidate's inclusion on a vendor list.

D. Within 60 days after a vendor list is filed with Docket Control, Staff shall issue a notice identifying each candidate on the vendor list that Staff has determined to be qualified to serve as independent monitor for the contemplated RFP process. In making its determination, Staff shall consider the experience of the candidates, the professional reputation of the candidates, and any objections filed by interested persons.

E. A load-serving entity that has completed the actions required by subsections (A) and (B) to comply with a particular Commission Decision is deemed to have complied with subsections (A) and (B) and is not required to repeat those actions.

F. A load-serving entity may retain as independent monitor for the contemplated RFP process and for its future RFP processes any of the candidates identified in Staff's notice.

G. A load-serving entity shall file with Docket Control a written notice of its retention of an independent monitor.

H. A load-serving entity is responsible for paying the independent monitor for its services and may charge a reasonable bidder's fee to each bidder in the RFP process to help offset the cost of the independent monitor's services. A load-serving entity may request recovery of the cost of the independent monitor's services, to the extent that the cost is not offset by bidder's fees, in a subsequent rate case. The Commission shall use its discretion in determining whether to allow the cost to be recovered through customer rates.

I. One week prior to the deadline for submitting bids, a load-serving entity shall provide the independent monitor a copy of any bid proposal prepared by the load-serving entity or entity affiliated with the load-serving entity and of any benchmark or reference cost the load-serving entity has developed for use in evaluating bids. The independent monitor shall take steps to secure the load-serving entity's bid proposal and any benchmark or reference cost so that they are inaccessible to any bidder, the load-serving entity, and any entity affiliated with the load-serving entity.

J. The independent monitor and load-serving entity must provide an opportunity for public review of a summary of each project proposal and for public comment on proposed bid ranking.

K. Upon Staff's request, the independent monitor shall provide status reports to Staff throughout the RFP process.

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 18. CLEAN AND RENEWABLE ENERGY STANDARD

Section

R14-2-1801. Definitions

1. "Affected Utility" means a public service corporation serving retail electric load in Arizona, but excluding any Utility Distribution Company with more than half of its customers located outside of Arizona.
2. "Annual Renewable Energy Requirement" means the portion of an Affected Utility's annual retail electricity sales that must come from Eligible Renewable Energy Resources.
3. "Arizona Dedicated Generation" means the energy produced from Dedicated Generation, adjusted as follows:
   a. If that generation produces more energy in a year than the Affected Utility's Arizona load, then Arizona Dedicated Generation is the sum of all renewable energy from Dedicated Generation, plus the energy from the remaining Dedicated Generation proportionately reduced by multiplying the energy produced from each generator times the ratio of 1) the Arizona load reduced by the energy produced by the renewable energy Dedicated Generation, to 2) the total megawatt-hours produced from the remaining (non-renewable) Dedicated Generation,
   b. If that generation produces less energy in a year than the Affected Utility's Arizona Load, power purchases by the Affected Utility that are not Dedicated Generation, but are needed to meet the Affected Utility's Arizona Load during the applicable calendar year, shall be considered Dedicated Generation with an emission rate equal to the Unspecified Power Rate.
4. "Arizona Load" means the megawatt-hours of electricity during a year that an Affected Utility sells to its Arizona retail customers, plus line losses, minus load that has Renewable Energy Resources dedicated to serve a particular customer, provided that the particular customer retains the Renewable Energy Credits or the Renewable Energy Credits are retired on their behalf by the Affected Utility as a part of a voluntary program, product, or sales, and are not used for compliance with any law or regulation in any jurisdiction.
5. "Base period emissions" means the average annual metric tons of carbon-dioxide that the Affected Utility emitted into the atmosphere from its Arizona Dedicated Generation during a consecutive three-calendar-year period of 2016 to 2018.
6. "Clean Energy Credit," or "CEC" means an instrument, in a physical or electronic format approved by the Commission that represents, for every gigawatt-hour produced by Arizona Dedicated Generation in a year, each metric ton of carbon-dioxide emissions less than one thousand. For any electric generating facility that is awarded Renewable Energy Credits associated with its electricity production, emissions of less than one-thousand metric tons per gigawatt-hour will only be recognized in the base period emissions determination, and in the award of Clean Energy Credits during a compliance period, if the Renewable Energy Credit associated with that production has been or will be retired by the Affected Utility, and has not and will not be retired for voluntary renewable energy sales or programs. The emission rate for energy from Renewable Energy Resources without Renewable Energy Credits that meet this requirement shall equal the applicable Unspecified Power Emission Rate.

7. "Clean Energy Resource" means an energy resource that operates with zero net Emissions.
8. "Commission" means the Arizona Corporation Commission.
9. "Community Distributed Generation" means a renewable generation facility that is located in the service territory of an Affected Utility where the beneficial use of the electricity generated by the facility is attributed to the subscribers. There shall be at least ten subscribers and the facility shall have a capacity of no more than 10 MW. The owner of the community distributed generation facility may be the Affected Utility or any other for-profit or non-profit entity or organization, including a subscriber organization that contracts to sell the output from the community distributed generation facility to the Affected Utility.
10. "Conventional Energy Resource" means an energy resource that is non-renewable in nature, such as natural gas, coal, oil, and uranium, or electricity that is produced with energy resources that are not Renewable Energy Resources.
11. "Customer Self-Directed Renewable Energy Option" means a Commission-approved program under which an Eligible Customer may self-direct the use of its allocation of funds collected pursuant to an Affected Utility's Tariff.
12. "Dedicated Generation" means electric energy production capacity that is assigned to the Affected Utility for Arizona ratemaking purposes, and that is either owned by the Affected Utility or a corporate affiliate, or committed to the Affected Utility or a corporate affiliate pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes, less any such capacity sold by the Affected Utility pursuant to an agreement of five years or longer that specifies the particular generation resource from which the energy comes, and less any renewable energy capacity committed to a particular customer or a voluntary renewable energy purchase program.
13. "Distributed Generation" means electric generation sited at a customer premises, providing electric energy to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.
14. "Distributed Renewable Energy Requirement" means a portion of the retail kilowatt-hours sold by an Affected that must be met with production derived from resources that qualify as Distributed Renewable Energy Resources pursuant to R14-2-1803(B).
15. "Distributed Solar Electric Generator" means electric generation sited at a customer premises, providing electric energy from solar electric resources to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.
16. "Eligible Customer" means an entity that pays Tariff funds of at least $25,000 annually for any number of related accounts or services within an Affected Utility's service area.
17. "Emissions" means carbon-dioxide (CO_2) emitted into the atmosphere.
18. "Gigawatt-hour" means one thousand megawatt-hours or one million kilowatt-hours.
19. "Green Pricing" means a rate option in which a customer elects to pay a tariffed rate premium for electricity derived from Eligible Renewable Energy Resources.
20. "Market Cost of Comparable Conventional Generation" means the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.
21. "Net Billing" means a system of billing a customer who installs an Eligible Renewable Energy Resource generator on the customer's premises for retail electricity purchased at retail rates while crediting the customer's bill for any customer-generated electricity sold to the Affected Utility at avoided cost.
22. "Net Metering" means a system of metering electricity by which the Affected Utility credits the customer at the full retail rate for each kilowatt-hour of electricity produced by an Eligible Renewable Energy Resource system installed on the customer-generator's side of the electric meter, up to the total amount of electricity used by that customer during an annualized period, and which compensates the customer-generator at the end of the annualized period for any excess credits at a rate equal to the Affected Utility's avoided cost of wholesale power. The Affected Utility does not charge the customer-generator any additional fees or charges or impose any equipment or other requirements unless the same is imposed on customers in the same rate class that the customer-generator would qualify for if the customer-generator did not have generation equipment.
23. "Renewable Energy Credit" means the unit created to track kWh derived from an Eligible Renewable Energy Resource or kWh equivalent of Conventional Energy Resources displaced by Distributed Renewable Energy Resources.
24. "Renewable Energy Resource" means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
25. "Tariff" means a Commission-approved rate designed to recover an Affected Utility's reasonable and prudent costs of complying with these rules.
26. "Unspecified Power Emission Rate" means the metric tons of CO_2 per megawatt-hour identified in the Environmental Protection Agency's eGRID reports for the North American Electric Reliability Council (NERC) sub-region from which the power was procured. For calculating base period emissions, 2016 shall be used for 2016 through 2018. For compliance periods, the most recent eGRID reports shall be used. In 2016 the eGRID AZNM sub-region rate was 0.474 mT/MWh, the eGRID NWPP sub-region rate was 0.295 mT/MWh, and the eGRID CAMX sub-region rate was 0.240 mT/MWh.

27. "Utility Distribution Company" means a public service corporation that operates, constructs, or maintains a distribution system for the delivery of power to retail customers.

28. "Wholesale Distributed Generation Component" means non-utility owners of Eligible Renewable Energy Resources that are located within the distribution system and that do not require a transmission line over 69 kv to deliver power at wholesale to an Affected Utility to meet its Annual Renewable Energy Requirements.

R14-2-1802. Clean Energy Requirement

A. Clean Energy Standard

1. An Affected Utility shall emit no more than its base period emissions in 2020, shall emit no more that ninety-six percent of its base period emissions in 2021, and shall continue to reduce its base period emissions by an additional four percent each year thereafter until January 1, 2045. For calendar year 2045 and thereafter emissions shall remain fixed at zero.
2. Each Affected Utility shall demonstrate compliance with the limitations of subsection (1) by the certified retirement of Clean Energy Credits (CECs). An Affected Utility shall first present and retire CECs on or before July 1, 2023 for compliance in the 2020 through 2022 periods, and shall retire CECs every three years thereafter for compliance during that intervening three calendar year period. The Commission will certify the retirement of CECs and otherwise assure compliance with this rule. If an Affected Utility retires an insufficient number of credits at the end of a compliance period, it shall satisfy that deficiency by retiring 125 percent of the deficiency on or before July 1 of the year following the end of the next three-year compliance period. An Affected Utility may not exercise this deficiency provision in any two consecutive compliance periods.
3. To demonstrate compliance, an Affected Utility shall retire one CEC per year for each megawatt-hour of its Arizona Load in that year, less the number of metric tons of its base period emissions reduced by the percentage required in that year under subsection 1. Specifically, at the end of each compliance period, the Affected Utility will retire the cumulative CECs required for each year of that period. In each year, the CEC retirement obligation equals the amount expressed by the following equation:

$$CEC_{retired} = L_y - E_b(1 - R_y)$$

y = year (2020, 2021…)
Ly = utility Arizona load (MWh) plus line losses in y, multiplied by 1.0 metric ton per MWh
Eb = base period emissions
Ry = the reduction required in y (e.g. 0.00 in 2020, 0.04 in 2021, 0.08 in 2022…)

B. Clean Energy Credits

1. The Commission will provide an Affected Utility one CEC each calendar year commencing in 2020 for each metric ton less than one thousand metric tons that it emits from its Arizona Dedicated Generation, for every gigawatt-hour produced by that generation in that year. The Commission will make this award by June 1 of the following year.
2. CECs may be sold, traded or otherwise transferred to any person, do not expire, and may be used at any time unless and until they are retired for compliance with this rule or another rule requiring carbon-dioxide reductions in another jurisdiction. Upon application by an Affected Utility, the Commission may allow credits, allowances, or other instruments from another jurisdiction or economic sector that has a program to require comparable and systematic reduction of carbon-dioxide emissions over time, and that accepts CECs into its program, to be used for compliance in Arizona.

C. Compliance Procedures

1. On or before July 1, 2020, each Affected Utility shall file with the Commission a verified statement of its base period emissions. That statement shall include work-papers, supporting evidence, and documentation. The statement shall also either include Arizona Department of Environmental Quality verification that the CO_2 emissions identified by the Affected Utility are correct and consistent with those reported to the Environmental Protection Agency's Greenhouse Gas Reporting program, per CFR Part 98, or an explanation of why that certification could not be obtained. This filing shall be served on all parties to the Affected Utility's last rate case, and notice of the filing shall be published in a newspaper or newspapers of general circulation in the Affected Utility's service area. If no protest to the statement is filed with the Commission within thirty (30) days of notice of the statement, it shall be deemed approved. If a protest is filed, the Commission will establish a procedure to determine by December 1, 2020 the appropriate base period emissions for the Affected Utility. Once established, the determination of base period emissions shall not be changed.
2. On or before April 1st of each calendar year commencing in 2021, each Affected Utility shall file with the Commission a verified statement of its entitlement to CECs for the prior calendar year, along with work-papers and other documentation supporting that statement. The statement shall also either include Arizona Department of Environmental Quality verification that the CO_2 emissions reported by the Affected Utility are correct and consistent with those reported to the Environmental Protection Agency's Greenhouse Gas Reporting program, per CFR Part 98, or an explanation of why that certification could not be obtained. This filing shall be served on all parties to the Affected Utility's last rate case, and notice of the filing shall be published in a newspaper or newspapers of general circulation in the Affected Utility's service area. The Affected Utility may develop an Excel-based credit tracking and information system to assist in fulfilling this requirement. This filing shall include:
   a. Information to establish the Affected Utility's entitlement to CECs based on the production and emissions from the Affected Utility's Arizona Dedicated Generation;
   b. a proposed format for the issuance of credits; and

c. an accounting and reconciliation of all credits that the Affected Utility has been awarded, has transferred, has banked, and has retired for compliance.

If no protest to the statement is filed with the Commission within thirty (30) days of notice of the filing, the Commission may immediately award the requested number of credits in the format proposed by the Affected Utility or another format determined by the Commission. If a protest is filed, or if the Commission determines that further inquiry is appropriate, it will establish a procedure to determine and award by September 1 of that same year the correct number of CECs.

D. Clean Energy Standard Advisory Committee

An advisory committee of no more than seven (7) members is established, to be chaired by a designee of the Commission, and to include a representative from an investor-owned utility, a rural electric cooperative, a consumer advocate, and an environmental advocate. The Advisory Committee will provide guidance for the implementation of the rule and will consider at least the following issues during its pendency:

a. Potential refinements or improvements to the rule;
b. Outreach opportunities to share experience with the rule with policymakers and others;
c. Refinements to the CEC amounts awarded for electric vehicles as their use expands and vehicle and generation technology advances;
d. Exchangeability of CECs with allowances, credits, or other similar instruments from other carbon-dioxide or greenhouse gas reduction programs; and
e. Capacity of the rule to satisfy and comply with existing or future requirements of law.

The Advisory Committee shall report to the Commission no less frequently than every three years, and shall issue a final report and disband on January 1, 2030.

R14-2-1803. Eligible Renewable Energy Resources

A. "Eligible Renewable Energy Resources" are applications of the following defined technologies that displace Conventional Energy Resources that would otherwise be used to provide electricity to an Affected Utility's Arizona customers:

1. "Biogas Electricity Generator" is a generator that produces electricity from gases that are derived from plant-derived organic matter, agricultural food and feed matter, wood wastes, aquatic plants, animal wastes, vegetative wastes, or wastewater treatment facilities using anaerobic digestion.
2. "Biomass Electricity Generator" is an electricity generator that uses any raw or processed plant-derived organic matter available on a sustainable and renewable basis and that has zero net life-cycle emissions, including: dedicated energy crops and trees; agricultural food and feed crops; agricultural crop wastes and residues; wood wastes and residues, including landscape waste, right-of-way tree trimmings, or small diameter forest thinnings that are 6" in diameter or less; dead and downed forest products; aquatic plants; animal wastes; other vegetative waste materials; non-hazardous plant matter waste material that is segregated from other waste; forest-related resources, such as harvesting and mill residue, pre-commercial thinnings, slash, and brush; miscellaneous waste, such as waste pellets, crates, and dunnage; and recycled paper fibers that are no longer suitable for recycled paper production, but not including painted, treated, or pressurized wood, wood contaminated with plastics or metals, tires, or recyclable post-consumer waste paper.
3. "Distributed Renewable Energy Resources" as defined in subsection (B).
4. "Eligible Hydropower Facilities" are hydropower generators that were in existence prior to 1997 and that satisfy one of the following two criteria:
   a. New Increased Capacity of Existing Hydropower Facilities: A hydropower facility that increases capacity due to improved technological or operational efficiencies or operational improvements resulting from improved or modified turbine design, improved or modified wicket gate assembly design, improved hydrological flow conditions, improved generator windings, improved electrical excitation systems, increases in transformation capacity, and improved system control and operating limit modifications. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the new, incremental kWh output resulting from the capacity increase that is delivered to Arizona customers to meet the Annual Renewable Energy Requirement.
   b. Generation from pre-1997 hydropower facilities that is used to firm or regulate the output of other eligible, intermittent renewable resources. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the kWh actually generated to firm or regulate the output of eligible intermittent Renewable Energy Resources and that are delivered to Arizona customers to meet the Annual Renewable Energy Requirements.
5. "Fuel Cells that Use Only Renewable Fuels" are fuel cell electricity generators that operate on renewable fuels, such as hydrogen created from water by Eligible Renewable Energy Resources. Hydrogen created from non-Renewable Energy Resources, such as natural gas or petroleum products, is not a renewable fuel.
6. "Geothermal Generator" is an electricity generator that uses heat from within the earth's surface to produce electricity.
7. "Hybrid Wind and Solar Electric Generator" is a system in which a Wind Generator and a solar electric generator are combined to provide electricity.
8. "Landfill Gas Generator" is an electricity generator that uses methane gas obtained from landfills to produce electricity.
9. "New Hydropower Generator of 10 MW or Less" is a generator, installed after January 1, 2006, that produces 10 MW or less and is either:
   a. A low-head, micro hydro run-of-the-river system that does not require any new damming of the flow of the stream; or

b. An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or
c. Generation using canals or other irrigation systems.

10. "Solar Electricity Resources" use sunlight to produce electricity by either photovoltaic devices or solar thermal electric resources.
11. "Wind Generator" is a mechanical device that is driven by wind to produce electricity.

B. "Distributed Renewable Energy Resources" are Community Distributed Generation as defined in section R14-2-1801(9) or applications of the following defined technologies that are located at a customer's premises and that displace Conventional Energy Resources that would otherwise be used to provide electricity to Arizona customers:

1. "Biogas Electricity Generator," "Biomass Electricity Generator," "Geothermal Generator," "Fuel Cells that Use Only Renewable Fuels," "New Hydropower Generator of 10 MW or Less," or "Solar Electricity Resources," as each of those terms is defined in subsections (A)(1), (A)(2), (A)(5), (A)(6), (A)(9), and (A)(10).
2. "Biomass Thermal Systems" and "Biogas Thermal Systems" are systems which use fuels as defined in subsections (A)(1) and (A)(2) to produce thermal energy and that comply with Environmental Protection Agency Certification Programs or are permitted by state, county, or local air quality authorities. For purposes of this definition "Biomass Thermal Systems" and "Biogas Thermal Systems" do not include biomass and wood stoves, furnaces, and fireplaces.
3. "Commercial Solar Pool Heaters" are devices that use solar energy to heat commercial or municipal swimming pools.
4. "Geothermal Space Heating and Process Heating Systems" are systems that use heat from within the earth's surface for space heating or for process heating.
5. "Renewable Combined Heat and Power System" is a Distributed Generation system, fueled by an Eligible Renewable Energy Resource, that produces both electricity and useful renewable process heat. Both the electricity and renewable process heat may be used to meet the Distributed Renewable Energy Requirement.
6. "Solar Daylighting" is the non-residential application of a device specifically designed to capture and redirect the visible portion of the solar beam, while controlling the infrared portion, for use in illuminating interior building spaces in lieu of artificial lighting.
7. "Solar Heating, Ventilation, and Air Conditioning" ("HVAC") is the combination of Solar Space Cooling and Solar Space Heating as part of one system.
8. "Solar Industrial Process Heating and Cooling" is the use of solar thermal energy for industrial or commercial manufacturing or processing applications.
9. "Solar Space Cooling" is a technology that uses solar thermal energy absent the generation of electricity to drive a refrigeration machine that provides for space cooling in a building.
10. "Solar Space Heating" is a method whereby a mechanical system is used to collect solar energy to provide space heating for buildings.
11. "Solar Water Heater" is a device that uses solar energy rather than electricity or fossil fuel to heat water for residential, commercial, or industrial purposes.
12. "Wind Generator of 1 MW or Less" is a mechanical device, with an output of 1 MW or less, that is driven by wind to produce electricity.

C. Except as provided in subsection (A)(4), Eligible Renewable Energy Resources shall not include facilities installed before January 1, 1997.

D. The Commission may adopt pilot programs in which additional technologies are established as Eligible Renewable Energy Resources or Distributed Renewable Energy Resources. Any such additional technologies shall be Renewable Energy Resources that produce electricity, replace electricity generated by Conventional Energy Resources, or replace the use of fossil fuels with Renewable Energy Resources. Energy storage technology that facilitates the integration of Renewable Energy Resources shall be eligible for these pilot programs. Energy conservation products, energy management products, energy efficiency products, or products that use non-renewable fuels shall not be eligible for these pilot programs.

R14-2-1804. Renewable Energy Credits

A. One Renewable Energy Credit shall be created for each kWh derived from an Eligible Renewable Energy Resource.

B. For Distributed Renewable Energy Resources, one Renewable Energy Credit shall be created for each 3,415 British Thermal Units of heat produced by a Solar Water Heating System, a Solar Industrial Process Heating and Cooling System, Solar Space Cooling System, Biomass Thermal System, Biogas Thermal System, or a Solar Space Heating System.

C. An Affected Utility may transfer Renewable Energy Credits to another party and may acquire Renewable Energy Credits from another party. A Renewable Energy Credit is owned by the owner of the Eligible Renewable Energy Resource from which it was derived unless specifically transferred.

D. All transfers of Renewable Energy Credits shall be appropriately documented to demonstrate that the energy associated with the Renewable Energy Credits meets the provisions of R14-2-1803.

E. Any contract by an Affected Utility for purchase or sale of energy or Renewable Energy Credits to meet the requirements of this Rule shall explicitly describe the transfer of rights concerning both energy and Renewable Energy Credits.

F. Except in the case of Distributed Renewable Energy Resources, Affected Utilities must demonstrate the delivery of energy from Eligible Renewable Energy Resources to their retail consumers such as by providing proof that the necessary transmission rights were reserved and utilized to deliver energy from Eligible Renewable Energy Resources to the Affected Utility's system, if transmission is required, or that the appropriate control area operators scheduled the energy from Eligible Renewable Energy Resources for delivery to the Affected Utility's system.

R14-2-1805. Annual Renewable Energy Requirement

A. In order to ensure reliable electric service at reasonable rates, each Affected Utility shall be required to satisfy an Annual Renewable Energy Requirement by obtaining Renewable Energy Credits from Eligible Renewable Energy Resources.

B. An Affected Utility's Annual Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the retail kWh sold by the Affected Utility during that calendar year:

2006	1.25%
2007	1.50%
2008	1.75%
2009	2.00%
2010	2.50%
2011	3.00%
2012	3.50%
2013	4.00%
2014	4.50%
2015	5.00%
2016	6.00%
2017	7.00%
2018	8.00%
2019	9.00%
2020	12.00%
2021	14.00%
2022	16.00%
2023	20.00%
2024	24.00%
2025	28.00%
2025	28.00%
2026	32.00%
2027	36.00%
2028	40.00%
2029	45.00%
2030 and after	50.00%

The annual increase in the annual percentage for each Affected Utility will be pro rated for the first year based on when the Affected Utility's funding mechanism is approved.

C. An Affected Utility may use Renewable Energy Credits acquired in any year to meet its Annual Renewable Energy Requirement.

D. Once a Renewable Energy Credit is used by any Affected Utility to satisfy these requirements, the credit is retired and cannot be subsequently used to satisfy these rules or any other regulatory requirement.

E. If an Affected Utility trades or sells environmental pollution reduction credits or any other environmental attributes associated with kWh produced by an Eligible Renewable Energy Resource, the Affected Utility may not apply Renewable Energy Credits derived from that same kWh to satisfy the requirements of these rules.

F. An Affected Utility may ask the Commission to preapprove agreements to purchase energy or Renewable Energy Credits from Eligible Renewable Energy Resources.

R14-2-1806. Distributed Renewable Energy Requirement

A. In order to improve system reliability, each Affected Utility shall be required to satisfy a Distributed Renewable Energy Requirement by measuring production from Distributed Renewable Energy Resources.

B. An Affected Utility's Distributed Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the retail kWhs sold by the Affected Utility during that calendar year, with the addition of measured production from Distributed Renewable Energy Resources that is produced and consumed behind the meter:

2020	4.0%
2021	4.6%
2022	5.2%

2023	5.8%
2024	6.4%
2025	7.0%
2026	7.6%
2027	8.2%
2028	8.8%
2029	9.4%
2030	10.0%

C. Production from Distributed Renewable Energy Resources will be measured for compliance with this requirement based on dedicated production meters installed by the Affected Utility at the customer's premise.

D. Distributed Renewable Energy Resources that are not Community Distributed Generation must have a nameplate capacity of 50kW-DC or less to be counted toward compliance with the Distributed Renewable Energy Requirement.

E. An Affected Utility may satisfy no more than 10 percent of its annual Distributed Renewable Energy Requirement from Community Distributed Generation owned by the Affected Utility.

R14-2-1807. Tariff

A. Within 60 days of the effective date of these rules, each Affected Utility shall file with the Commission a Tariff in substantially the same form as the Sample Tariff set forth in these rules that proposes methods for recovering the reasonable and prudent costs of complying with these rules. The specific amounts in the Sample Tariff are for illustrative purposes only and Affected Utilities may submit, with proper support, Tariff filings with alternative surcharge amounts.

B. The Affected Utility's Tariff filing shall provide the following information:

1. Financial information and supporting data sufficient to allow the Commission to determine the Affected Utility's fair value for purposes of evaluating the Affected Utility's proposed Tariff. Information submitted in the format of the Annual Report required under R14-2-212(G)(4) will be the minimum information necessary for filing a Tariff application but Commission Staff may request additional information depending upon the type of Tariff filing that is submitted;
2. A discussion of the suitability of the Sample Tariff set forth in Appendix A for recovering the Affected Utility's reasonable and prudent costs of complying with these rules;
3. Data to support the level of costs that the Affected Utility contends will be incurred in order to comply with these rules;
4. Data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation; and
5. Any other information that the Commission believes will be relevant to the Commission's consideration of the Tariff filing.

C. The Commission will approve, modify, or deny a Tariff proposed pursuant to subsection (A) within 180 days after the Tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-1805(B), and Distributed Renewable Energy Requirement, as set forth in R14-2-1806(B), will be effective upon Commission approval of the Tariff filed pursuant to this Section.

D. If an Affected Utility has an adjustor mechanism for the recovery of costs related to Annual Renewable Energy Requirements, the Affected Utility may file a request to reset its adjustor mechanism in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all the information required by subsection (B), except that it may omit information specifically related to the fair value determination. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-1805(B), and Distributed Renewable Energy Requirement, as set forth in R14-2-1806(B), will be effective upon Commission approval of the adjustor mechanism rate filed pursuant to this Section.

E. An Affected Utility may file a rate case pursuant to R14-2-103 in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all information required by subsection (B).

F. For Eligible Renewable Energy Resources acquired by an Affected Utility after January 1, 2020, the Affected Utility shall recover the costs of those Eligible Renewable Energy Resources by the same method as the Affected Utility recovers its costs for Conventional Energy Resources.

R14-2-1808. Customer Self-Directed Renewable Energy Option

A. By January 1, 2007, each Affected Utility shall file with Docket Control a Tariff by which an Eligible Customer may apply to an Affected Utility to receive funds to install distributed Renewable Energy Resources. The funds annually received by an Eligible Customer pursuant to this Tariff may not exceed the amount annually paid by the Eligible Customer pursuant to the Affected Utility's Tariff.

B. An Eligible Customer seeking to participate in this program shall submit to the Affected Utility a written application that describes the Renewable Energy Resources that it proposes to install and the projected cost of the project. An Eligible Customer shall provide at least half of the funding necessary to complete the project described in its application.

C. All Renewable Energy Credits derived from the project shall belong to the Affected Utility.

R14-2-1809. Uniform Credit Purchase Program

A. The Director of the Utilities Division shall establish a Uniform Credit Purchase Program working group, which will study issues related to implementing Distributed Renewable Energy Resources. The working group shall address the consumer participation process, budgets, incentive levels, eligible technologies, system requirements, installation requirements, and any other issues that are relevant to encouraging the implementation of Distributed Renewable Energy Resources. No later than March 1, 2007, the Director of the Utilities Division shall file a staff report with recommendations for Uniform Credit Purchase Programs.

B. No later than July 1, 2007, each Affected Utility shall file a Uniform Credit Purchase Program for Commission review and approval.

R14-2-1810. Net Metering and Interconnection Standards

The Commission Staff shall host a series of workshops addressing the issues of rate design including Net Metering and interconnection standards. Upon completion of this task, and the adoption of rules or standards, if appropriate, each Affected Utility shall file conforming Net Metering tariffs and interconnection standards in Docket Control.

R14-2-1811. Renewable Energy Standard Compliance Reports

A. Beginning April 1, 2007, and every April 1st thereafter, each Affected Utility shall file with Docket Control a report that describes its compliance with the requirements of these rules for the previous calendar year and provides other relevant information. The Affected Utility shall also transmit to the Director of the Utilities Division an electronic copy of this report that is suitable for posting on the Commission's web site.

B. The compliance report shall include the following information:

1. The actual kWh of energy produced within its service territory and the actual kWh of energy or equivalent obtained from Eligible Renewable Energy Resources, differentiating between kWhs for which the Affected Utility owns the Renewable Energy Credits and kWhs produced in the Affected Utility's service territory for which the Affected Utility does not own the Renewable Energy Credits;
2. The actual kWh of energy obtained from Distributed Renewable Energy Resources;
3. The kWh of energy or equivalent obtained from Eligible Renewable Energy Resources normalized to reflect a full year's production;
4. The kWh of energy obtained from Distributed Renewable Energy Resources normalized to reflect a full year's production;
5. The kW of generation capacity, disaggregated by technology type;
6. Cost information regarding cents per actual kWh of energy obtained from Eligible Renewable Energy Resources and cents per kW of generation capacity, disaggregated by technology type;
7. A breakdown of the Renewable Energy Credits used to satisfy the Annual Renewable Energy Requirement and appropriate documentation of the Affected Utility's receipt of those Renewable Energy Credits;
8. A description of the Affected Utility's procedures for choosing Eligible Renewable Energy Resources and a certification from an independent auditor that those procedures are fair and unbiased and have been appropriately applied;
9. A discussion of the type and scale of Eligible Renewable Resources proposed in or near communities, including but not limited to tribal communities, impacted by the Affected Utility's closure of a Conventional Energy Resource and reasons why those Renewable Energy Resources were chosen or rejected; and
10. Whether the costs of the Affected Utility's Eligible Renewable Energy Resources will be recovered through the renewable energy tariff or through a rate case.

C. The Commission may consider all available information and may hold a hearing to determine whether an Affected Utility's compliance report satisfied the requirements of these rules.

R14-2-1812. Renewable Energy Standard Implementation Plans

A. Beginning July 1, 2007, and every July 1st thereafter, each Affected Utility shall file with Docket Control for Commission review and approval a plan that describes how it intends to comply with these rules for the next calendar year. The Affected Utility shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's web site to the Director of the Utilities Division.

B. The implementation plan shall include the following information:

1. A description of the Eligible Renewable Energy Resources, identified by technology, proposed to be added by year for the next five years and a description of the kW and kWh to be obtained from each of those resources;
2. The estimated cost of each Eligible Renewable Energy Resource proposed to be added, including cost per kWh and total cost per year;
3. A description of the method by which each Eligible Renewable Energy Resource is to be obtained, such as self-build, customer installation, or request for proposals;
4. A description of the economic development opportunities for each Eligible Renewable Energy Resource proposed to be added in or near communities, including but not limited to tribal communities, impacted by the Affected Utility's closure of a Conventional Energy Resource;
5. A description of programs considered or proposed for incentivizing deployment of Distributed Renewable Energy Resources;
6. A proposal that evaluates whether the Affected Utility's existing rates allow for the ongoing recovery of the reasonable and prudent costs of complying with these rules, including a Tariff application that meets the requirements of R14-2-1807 and addresses the Sample Tariff set forth in Appendix A if necessary; and

7. A line item budget that allocates specific funding for Distributed Renewable Energy Resources, for the Customer Self-Directed Renewable Energy Option, for power purchase agreements, for utility-owned systems, and for each Eligible Renewable Energy Resource described in the Affected Utility's implementation plan.

C. The Commission may hold a hearing to determine whether an Affected Utility's implementation plan satisfies the requirements of these rules.

R14-2-1813. Electric Power Cooperatives

A. Within 60 days of the effective date of these rules, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year and a Tariff that proposes methods for recovering the reasonable and prudent costs of complying with its proposed plan and addresses the Sample Tariff set forth in Appendix A. The cooperative shall also transmit electronic copies of these filings that are suitable for posting on the Commission's web site to the Director of the Utilities Division. Upon Commission approval of this plan, its provisions shall substitute for the requirements of R14-2-1805 and R14-2-1806 for the electric power cooperative proposing the plan.

B. Beginning July 1, 2007, and every July 1st thereafter, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year. The cooperative shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's web site to the Director of the Utilities Division.

R14-2-1814. Enforcement and Penalties

A. If an Affected Utility fails to meet the annual requirements set forth in R14-2-1805 and R14-2-1806, it shall include with its annual compliance report a notice of noncompliance.

B. The notice of noncompliance shall provide the following information:

1. A computation of the difference between the Renewable Energy Credits required by R14-2-1805 and the kWh required by R14-2-1806 and the amount actually obtained,
2. A plan describing how the Affected Utility intends to meet the shortfall from the previous calendar year in the current calendar year, and
3. An estimate of the costs of meeting the shortfall.

C. If the Commission finds after affording an Affected Utility notice and an opportunity to be heard that the Affected Utility has failed to comply with its implementation plan approved by the Commission as set forth in R14-2-1812, the Commission may find that the Affected Utility shall not recover the costs of meeting the shortfall described in R14-2-1814(B) in rates.

D. If the Commission finds after affording an Affected Utility notice and opportunity to be heard that the Affected Utility has failed to retire a sufficient number of Clean Energy Credits at the end of a compliance period, the Commission may find that the Affected Utility shall not recover the costs of meeting the shortfall in rates.

E. Nothing herein is intended to limit the actions the Commission may take or the penalties the Commission may impose pursuant to Arizona Revised Statutes, Chapter 2, Article 9. An Affected Utility is entitled to notice and an opportunity to be heard prior to Commission action or imposition of penalties.

R14-2-1815. Waiver from the Provisions of this Article

A. The Commission may waive compliance with any provision of this Article for good cause.

B. Any Affected Utility may petition the Commission to waive its compliance with any provision of this Article for good cause.

C. A petition for a waiver from these rules shall, at a minimum:

1. State the reason(s) for the waiver request;
2. Identify each section of this rule for which a waiver is requested;
3. Describe the effect the waiver will have on compliance with this rule;
4. Describe how the waiver will not compromise, or will further, the rule's purposes; and
5. Describe why the waiver would be a reasonable alternative to the rule's requirements.

D. A petition filed pursuant to these rules shall have priority over other matters filed at the Commission.

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 24. ELECTRIC ENERGY EFFICIENCY STANDARDS

Section

R14-2-2401. Definitions

In this Article, unless otherwise specified:

1. "Adjustment mechanism" means a Commission approved provision in an affected utility's rate schedule allowing the affected utility to increase and decrease a certain rate or rates, in an established manner, when increases or decreases in specific costs are incurred by the affected utility.
2. "Affected utility" means a public service corporation that provides electric service to retail customers in Arizona.
3. "Baseline" means the level of electricity demand, electricity consumption, and associated expenses estimated to occur in the absence of a DSM portfolio, determined as provided in R14-2-2413.
4. "CHP" means combined heat and power, which is using a primary energy source to simultaneously produce electrical energy and useful process heat.
5. "Conservation voltage reduction" or voltage/VAR optimization means the deployment of technologies and strategies to intentionally operate the transmission and distribution system to provide customer voltages in the lower end of the acceptable voltage range in order to achieve energy and demand reductions for customers.
6. "Commission" means the Arizona Corporation Commission.
7. "Cost-effective" means that the DSM portfolio being evaluated meets the societal test, as determined under R14-2-2412.
8. "Customer" means the person or entity in whose name service is rendered to a single contiguous field, location, or facility, regardless of the number of meters at the field, location, or facility.
9. "Delivery system" means the infrastructure through which an affected utility transmits and then distributes electrical energy to its customers.
10. "Demand savings" means the load reduction, measured in kW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.
11. "Demand response" means modification of customers' electricity consumption patterns, affecting the timing or quantity of customer demand and usage, achieved through intentional actions taken by an affected utility or customer.

12. "Distributed generation" means the production of electricity on the customer's side of the meter, for use by the customer, through a technology such as solar photovoltaic panels or CHP.
13. "DSM" means demand-side management, the implementation and maintenance of one or more DSM programs that comprise a DSM portfolio.
14. "DSM measure" means any material, device, technology, educational program, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off-peak periods and includes CHP used to displace space heating, water heating, or another load.
15. "DSM portfolio" means the entire suite of DSM programs offered to residential customers, including low-income customers; or to non-residential customers.
16. "DSM program" means one or more DSM measures provided as part of a single offering to customers.
17. "DSM tariff" means a Commission-approved schedule of rates designed to recover an affected utility's reasonable and prudent costs of complying with this Article.
18. "Electric generation system" means all personal property and operating real property used for the purpose of generating electricity.
19. "Electric utility" means a public service corporation providing electric service to the public.
20. "Energy efficiency" means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end use customers.
21. "Energy efficiency standard" means the reduction in retail energy sales, in percentage of retail kWh sales, required to be achieved through an affected utility's approved DSM portfolio as prescribed in R14-2-2404.
22. "Energy savings" means the reduction in a customer's energy consumption directly resulting from a DSM portfolio, expressed in kWh.
23. "Energy service company" means a company that provides a broad range of services related to energy efficiency, including energy audits, the design and implementation of energy efficiency projects, and the installation and maintenance of energy efficiency measures.
24. "Environmental benefits" means avoidance of costs for compliance, or reduction in environmental impacts, for things such as, but not limited to: a. Water use and water contamination, b. Monitoring storage and disposal of solid waste such as coal ash (bottom and fly), c. Adverse health effects from burning fossil fuels, and d. Pollutant emissions from transportation and production of fuels and electricity.
25. "Incremental benefits" means amounts saved through avoiding costs for fuel, purchased power, new generation capacity, transmission and distribution capacity, and other cost items necessary to provide electric utility service, along with other improvements in societal welfare, such as through avoided environmental impacts, including, but not limited to, water consumption savings, air emission reduction, reduction in coal ash, and reduction of nuclear waste.
26. "Incremental costs" means the additional expenses of a DSM portfolio, relative to baseline.
27. "Independent program administrator" means an impartial third party employed to provide objective oversight of energy efficiency programs.
28. "kW" means kilowatt.
29. "kWh" means kilowatt-hour.
30. "Leveraging" means combining resources to more effectively achieve an energy efficiency goal, or to achieve greater energy efficiency savings, than would be achieved without combining resources.
31. "Load management" means actions taken or sponsored by an affected utility to reduce peak demands, such as direct control of customer demands through utility-initiated interruption or cycling, thermal storage, or educational campaigns to encourage customers to shift loads.
32. "Low-income customer" means a customer with a below average level of household income, as defined in an affected utility's Commission-approved DSM portfolio description.
33. "Market transformation" means strategic efforts to induce lasting structural or behavioral changes in the market that result in increased energy efficiency.
34. "Net benefits" means the incremental benefits resulting from DSM minus the incremental costs of DSM.
35. "Non-energy benefits" means improvements in societal welfare that are outside the scope of utility system benefits, including but not limited to increased productivity, increased comfort, increased property value, environmental benefits, reduced compliance costs, and water savings.
36. "Portfolio costs" means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating a Commission-approved DSM portfolio.
37. "Self-direction" means an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments upon application by the customer.
38. "Societal Test" means a cost-effectiveness test of a DSM portfolio that includes both utility system and non-energy benefits and both utility and customer costs to implement a DSM portfolio; that uses a social discount rate to determine the net present value of costs and benefits that is based on the yield for long-term U.S. Treasury securities up to a cap

of 3%; that uses a non-energy benefits adder of at least 50% applied to the sum of other quantifiable benefits for low-income programs within a DSM portfolio; and that uses a non-energy benefits adder of at least 25% applied to the sum of other quantifiable benefits for all other programs within a DSM portfolio.

39. "Staff" means individuals working for the Commission's Utilities Division, whether as employees or through contract.
40. "Thermal envelope" means the collection of building surfaces, such as walls, windows, doors, floors, ceilings, and roofs, that separate interior conditioned (heated or cooled) spaces from the exterior environment.

R14-2-2402. Applicability

This Article applies to each affected utility classified as Class A according to R14-2-103(A)(3)(q), unless the affected utility is an electric distribution cooperative that has fewer than 25% of its customers in Arizona.

R14-2-2403. Goals and Objectives

A. An affected utility shall design each DSM portfolio:
   1. To be cost-effective, and
   2. To accomplish the following:
      a. Energy efficiency,
      b. Load management, and/or demand response.

B. An affected utility shall consider the following when planning and implementing a DSM portfolio:
   1. Whether the DSM portfolio will achieve cost-effective energy savings and peak demand reductions;
   2. Whether the DSM portfolio will advance market transformation and achieve sustainable savings, reducing the need for future market interventions; and
   3. Whether the affected utility can ensure a level of funding adequate to sustain the DSM portfolio and allow the DSM portfolio to achieve its targeted goal.

C. An affected utility shall:
   1. Offer DSM programs within a DSM portfolio that will provide an opportunity for all affected utility customer segments to participate, and
   2. Allocate not less than 5% of DSM portfolio resources specifically to low-income customers.

R14-2-2404. Energy Efficiency Standards

A. Except as provided in R14-2-2418, in order to ensure reliable electric service at reasonable ratepayer rates and costs, by December 31, 2030, an affected utility shall, through cost effective DSM portfolios, achieve cumulative annual energy savings, measured in kWh, equivalent to at least 35% of the affected utility's retail electric energy sales for calendar year 2029 and in every year thereafter.

B. An affected utility shall, by the end of each calendar year, meet at least the cumulative annual energy efficiency standard listed in Table 1 for that calendar year. An illustrative example of how the required energy savings would be calculated is shown in Table 2. An illustrative example of how the standard could be met in 2030 is shown in Table 4.

Table 1. Energy Efficiency Standard

CALENDAR YEAR	ENERGY EFFICIENCY STANDARD (Cumulative Annual Energy Savings by the End of Each Calendar Year as a Percentage of the Retail Energy Sales in the Prior Calendar Year)
2011	1.25%
2012	3.00%
2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

2021	23.30%
2022	24.60%
2023	25.90%
2024	27.20%
2025	28.50%
2026	29.80%
2027	31.10%
2028	32.40%
2029	33.70%
2030	35.00%

Table 2. Illustrative Example of Calculating Required Energy Savings

CALENDAR YEAR	A RETAIL SALES (kWh)	B ENERGY EFFICIENCY STANDARD	C REQUIRED CUMULATIVE ENERGY SAVINGS (B of current year × A of prior year)
2010	100,000,000		0
2011	100,750,000	1.25%	1,250,000
2012	101,017,500	3.00%	3,022,500
2013	101,069,925	5.00%	5,050,875
2014	100,915,646	7.25%	7,327,570
2015	100,821,094	9.50%	9,586,986
2016	100,517,711	12.00%	12,098,531
2017	100,293,499	14.50%	14,575,068
2018	100,116,043	17.00%	17,049,895
2019	99,986,628	19.50%	19,522,628
2020	99,902,384	22.00%	21,997,058
2021	100,841,388	23.30%	23,277,255
2022	101,785,056	24.60%	24,806,981
2023	102,748,740	25.90%	26,362,329
2024	103,732,607	27.20%	27,947,657
2025	104,736,836	28.50%	29,563,793
2026	105,761,611	29.80%	31,211,577
2027	106,807,126	31.10%	32,891,861
2028	107,873,584	32.40%	34,605,509
2029	108,961,195	33.70%	36,353,398
2030	110,070,178	35.00%	38,136,418

C. An affected utility's measured reductions in peak demand resulting from cost-effective demand response and load management programs may comprise up to one percentage points of the 35% energy efficiency standard through 2030, with peak demand reduction capability from demand response converted to an annual energy savings equivalent based on its actual load factor or 4%, whichever is greater. The credit for demand response and load management peak demand reductions shall not exceed 5% of the energy efficiency standard set forth in subsection (B) for any year through 2030.

D. An affected utility's energy savings resulting from DSM energy efficiency programs implemented before the effective date of this Article, but after 2004, may be credited toward meeting the energy efficiency standard set forth in subsection (B) through 2020. The total energy savings credit for these pre-rules energy efficiency programs shall not exceed 4% of the affected utility's retail energy sales in calendar year 2005. A portion of the total energy savings credit for these pre-rules energy efficiency programs may be applied each year, from 2016 through 2020, as listed in Table 3, Column A.

Table 3. Credit for Pre-Rules Energy Savings

CALENDAR YEAR	A CREDIT FOR THE PRE-RULES ENERGY SAVINGS APPLIED IN	B CUMULATIVE APPLICATION OF THE CREDIT FOR THE PRE-RULES

	EACH YEAR (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Shall Be Applied in the Year)	ENERGY SAVINGS IN 2016-2020 (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Are Credited by the End of Each Year)
2016	7.5%	7.5%
2017	15.0%	22.5%
2018	20.0%	42.5%
2019	25.0%	67.5%
2020	32.5%	100.0%

E. An affected utility may count toward meeting the standard up to one-third of the energy savings resulting from energy efficiency building codes and energy efficiency appliance standards, provided that the affected utility played a direct role in achieving the savings through DSM program implementation. The partial credit for building code energy savings or energy efficiency appliance standards shall be quantified and reported through a measurement and evaluation study undertaken by the affected utility and shall be commensurate with the direct role that the affected utility played to achieve the savings through DSM program implementation.

F. An affected utility may count the energy savings from combined heat and power (CHP) systems that do not qualify under the Renewable Energy Standard toward meeting the energy efficiency standard, provided that the affected utility played a direct role in supporting the implementation of a CHP system through DSM program implementation. The credit for savings from CHP shall be quantified and reported through a measurement and evaluation study undertaken by the affected utility and shall be commensurate with the direct role that the affected utility played to achieve the savings through DSM program implementation.

G. An affected utility may count a customer's energy savings resulting from self-direction toward meeting the standard.

H. With the exception of conservation voltage reduction, an affected utility's energy savings resulting from efficiency improvements to its transmission or distribution system may not be counted toward meeting the standard.

I. An affected utility's energy savings resulting from efficiency improvements made directly to its electric generation system, including heat rate improvements to power plants, may not be counted toward meeting the standard.

J. An affected utility's energy savings used to meet the energy efficiency standard will be assumed to continue through the year 2030 or, if expiring before the year 2030, to be replaced with a DSM portfolio and programs having at least the same level of efficiency.

Table 4. Illustrative Example of How the Energy Standard Could Be Met in 2030

	2030 Energy Efficiency Standard	2029 Retail Sales (kWh)	Required Cumulative Annual Energy Savings (kWh)
Total	35.00%	108,961,195	38,136,418
Breakdown of Savings and Credits Used To Meet 2030 Standard:			
			Cumulative Annual Energy Savings or Credit (kWh)
Demand Response Credit R14-2-2404(C)	Up to 1.00%		1,089,612
Pre-rules Savings Credit R14-2-2404(D)			1,100,000*
Building Code R14-2-2404(E)			1,000,000
CHP R14-2-2404(F)			500,000
Self-direction R14-2-2404(G)			100,000
Energy Efficiency R14-2-2404(A)			34,346,806
Total			38,136,418

*The total pre-rules savings credit is capped at 4% of 2005 retail energy sales, and the total credit is allocated over five years from 2016 to 2020. The credit shown above represents an estimate of the portion of the total credit that can be taken in 2020, or 32.5% of the total credit allowed.

R14-2-2405. Implementation Plans

A. Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.

B. The implementation plan shall include the following information:
   1. Except for the initial implementation plan, a description of the affected utility's compliance with the requirements of this Article for the previous calendar year;
   2. Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary;
   3. Except for the initial implementation plan, which shall describe only the next calendar year, a description of each DSM program within a DSM portfolio to be newly implemented or continued in the next two calendar years and an estimate of the annual kWh and kW savings projected to be obtained through each DSM portfolio and program;
   4. The estimated total cost and cost per kWh reduction of each DSM measure, program, and portfolio described in subsection (B)(3);
   5. A DSM tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable; and
   6. For each new DSM program or DSM measure that the affected utility desires to implement within a DSM portfolio, a program proposal complying with R14-2-2407.

C. An affected utility shall notify its customers of its annual implementation plan filing through a notice in its next regularly scheduled customer bills.

D. The Commission may hold a hearing to determine whether an affected utility's implementation plan satisfies the requirements of this Article within 180 days after such implementation plan is filed with the Commission. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.

E. An affected utility's Commission-approved implementation plan, and the DSM portfolio and programs authorized thereunder, shall continue in effect until the Commission takes action on a new implementation plan for the affected utility.

F. A utility shall not implement any program changes proposed in an implementation plan until such changes are approved by the Commission.

R14-2-2406. DSM Tariffs

A. An affected utility's DSM tariff filing shall include the following:
   1. A detailed description of each method proposed by the affected utility to recover the reasonable and prudent costs associated with implementing the affected utility's intended DSM portfolio;
   2. Financial information and supporting data sufficient to allow the Commission to determine the affected utility's fair value, including, at a minimum, the information required to be submitted in a utility annual report filed under R14-2-212(G)(4);
   3. Data supporting the level of costs that the affected utility believes will be incurred in order to comply with this Article; and
   4. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.

B. The Commission shall approve, modify, or deny a tariff filed pursuant to subsection (A) within 180 days after the tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.

C. If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing a DSM portfolio, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and (3).

R14-2- 2407. Commission Review and Approval of DSM Programs and DSM Measures

A. An affected utility shall obtain Commission approval before implementing a new DSM program.

B. An affected utility may apply for Commission approval of a DSM program by submitting a proposal either as part of its DSM portfolio implementation plan submitted under R14-2-2405 or through a separate application that identifies the DSM portfolio under which the DSM program will be added.

C. A DSM portfolio or program proposal shall include the following:
   1. A description of the DSM programs and DSM measures that the affected utility desires to implement as part of the DSM portfolio,
   2. The affected utility's objectives and rationale for the DSM programs and portfolio,
   3. A description of the market segment at which the DSM programs and portfolio is aimed,
   4. An estimated level of customer participation in the DSM programs and portfolio,
   5. An estimate of the baseline for the components of the DSM portfolio,
   6. The estimated societal benefits and savings from the DSM programs and portfolio,
   7. The estimated societal costs of the DSM programs and portfolio,
   8. The estimated environmental benefits to be derived from the DSM programs and portfolio,
   9. The estimated benefit-cost ratio of the DSM programs and portfolio,
   10. The affected utility's marketing and delivery strategy,
   11. The affected utility's estimated annual costs and budget for the DSM programs and portfolio,
   12. The implementation schedule for the DSM programs and portfolio,
   13. A description of the affected utility's plan for monitoring and evaluating the DSM programs and portfolio, and
   14. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.

D. In determining whether to approve a DSM proposal, the Commission shall consider:
   1. The extent to which the Commission believes the DSM portfolio will meet the goals set forth in R14-2-2403(A), and
   2. All of the considerations set forth in R14-2-2403(B).

E. Staff may request modifications of an on-going DSM portfolio or DSM programs within a DSM portfolio to ensure consistency with this Article. The Commission shall allow affected utilities adequate time to notify customers of modifications.

R14-2-2408. Parity and Equity

A. An affected utility shall develop and propose DSM programs within DSM portfolios for:
   1. Residential customers, including low-income customers, and
   2. Non-residential customers.

B. No less than 5% of the total DSM budget shall be devoted to programs or program components for low-income customers.

C. An affected utility shall allocate DSM funds collected from residential customers and from non-residential customers proportionately to those customer classes to the extent practicable.

D. The affected utility costs of DSM programs for low-income customers shall be borne by all customer classes, except where a customer or customer class is specifically exempted by Commission order.

E. DSM funds collected by an affected utility shall be used, to the extent practicable, to benefit that affected utility's customers.

F. All customer classes of an affected utility shall bear the costs of DSM by payment through a non-bypassable mechanism, unless a customer or customer class is specifically exempted by Commission order.

R14-2-2409. Reporting Requirements

A. By March 1 of each year, an affected utility shall submit to the Commission, in a Commission-established docket for that year, a DSM progress report providing information for each of the affected utility's Commission-approved DSM portfolios and programs within each portfolio and including at least the following:
   1. An analysis of the affected utility's progress toward meeting the annual energy efficiency standard;
   2. A list of the affected utility's current Commission-approved DSM portfolios and programs within each portfolio, organized by customer segment;
   3. A description of the findings from any research projects completed during the previous year; and
   4. The following information for each Commission-approved DSM portfolio and programs within each portfolio:
      a. A brief description;
      b. Goals, objectives, and savings targets;
      c. The level of customer participation during the previous year;
      d. The costs incurred during the previous year, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;
      e. A description and the results of evaluation and monitoring activities during the previous year;
      f. Savings realized in kW, kWh, therms, and BTUs, as appropriate;
      g. The environmental and non-energy benefits realized, including reduced emissions and water savings;
      h. Incremental benefits and net benefits, in dollars;
      i. Performance-incentive calculations for the previous year;
      j. Problems encountered during the previous year and proposed solutions;
      k. A description of any modifications proposed for the following year; and
      l. Whether the affected utility proposes to terminate any DSM program within a DSM portfolio and the proposed date of termination.

B. By September 1 of each year, an affected utility shall file a status report including a tabular summary showing the following for each current Commission-approved DSM portfolio and program within each portfolio of the affected utility:
   1. Semi-annual expenditures compared to annual budget, and
   2. Participation rates.

C. An affected utility shall file each report required by this Section with Docket Control, where it will be available to the public, and shall make each such report available to the public upon request.

D. An affected utility may request within its implementation plan that these reporting requirements supersede specific existing DSM reporting requirements.

R14-2-2410. Cost Recovery

A. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM portfolio and programs within a DSM portfolio if the DSM portfolio is all of the following:
   1. Approved by the Commission before it is implemented,
   2. Implemented in accordance with a Commission-approved program proposal or implementation plan, and
   3. Monitored and evaluated for cost-effectiveness pursuant to R14-2-2415.

B. An affected utility shall monitor and evaluate each DSM portfolio and program, as provided in R14-2-2415, to determine whether the DSM portfolio is cost-effective and otherwise meets expectations.

C. If an affected utility determines that a DSM portfolio is not cost-effective or otherwise does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2409 a proposal to modify or terminate the DSM portfolio.

D. An affected utility shall recover its DSM costs concurrently, on an annual basis, with the spending for a DSM portfolio, unless the Commission orders otherwise.

E. An affected utility may recover costs from DSM funds for any of the following items, if the expenditures will enhance DSM:
   1. Incremental labor attributable to DSM development,
   2. A market study,
   3. A research and development project such as applied technology assessment,
   4. Consortium membership, or
   5. Another item that is difficult to allocate to an individual DSM portfolio.

F. The Commission may impose a limit on the amount of DSM funds that may be used for the items in subsection (E).

G. If goods and services used by an affected utility for DSM have value for other affected utility functions, programs, or services, the affected utility shall divide the costs for the goods and services and allocate funding proportionately.

H. An affected utility shall allocate DSM costs in accordance with generally accepted accounting principles.

I. The Commission shall review and address financial disincentives, recovery of fixed costs, and recovery of net lost income/revenue, due to Commission-approved DSM portfolios and programs, if an affected utility requests such review in its rate case and provides documentation/records supporting its request in its rate application.

J. An affected utility, at its own initiative, may submit to the Commission twice-annual reports on the financial impacts of its Commission-approved DSM portfolios and programs, including any unrecovered fixed costs and net lost income/revenue resulting from its Commission-approved DSM portfolios and programs.

R14-2-2411. Performance Incentives

In the implementation plans required by R14-2-2405, an affected utility may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in R14-2-2404. The Commission may also consider performance incentives in a general rate case.

R14-2-2412. Cost-effectiveness

A. An affected utility shall ensure that the incremental benefits to society of the affected utility's overall DSM portfolio exceed the incremental costs to society of the DSM portfolio.

B. The overall DSM portfolio shall be evaluated to determine cost-effectiveness using the societal test.

C. The analysis of a DSM portfolio's cost-effectiveness may include:
   1. Costs and benefits associated with reliability, improved system operations, environmental impacts, and customer service;
   2. Savings of both natural gas and electricity; and
   3. Any uncertainty about future streams of costs or benefits.

D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively.

E. For purposes of analyzing DSM portfolio cost-effectiveness, market transformation programs within a DSM portfolio shall be evaluated by measuring market effects compared to program costs.

F. For purposes of analyzing DSM portfolio cost-effectiveness, educational programs that support consumer and business adoption of energy efficiency, load management or demand response measures are not required to be cost effective and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test.

G. For purposes of analyzing DSM portfolio cost-effectiveness, research and development and pilot programs are not required to be cost-effective and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test.

H. For purposes of evaluating DSM portfolio cost-effectiveness, an affected utility's low-income customer programs are not required to be cost-effective and shall be excluded from the portfolio cost-effectiveness evaluation if their inclusion causes the portfolio not to pass the societal test.

R14-2-2413. Baseline Estimation

A. To determine the baseline, an affected utility shall estimate the level of electric demand and consumption and the associated costs that would have occurred in the absence of a DSM portfolio, including the DSM programs or DSM measures within a DSM portfolio.

B. For demand response programs, an affected utility shall use customer load profile information to verify baseline consumption patterns and the peak demand savings resulting from demand response actions.

C. For installations or applications that have multiple fuel choices, an affected utility shall determine the baseline using the same fuel source actually used for the installation or application.

R14-2-2414. Fuel Neutrality

A. An affected utility shall use DSM funds collected from electric customers for electric DSM programs, unless otherwise ordered by the Commission.

B. An affected utility may use DSM funds collected from electric customers for thermal envelope improvements.

R14-2-2415. Monitoring, Evaluation, and Research

A. An affected utility shall monitor and evaluate each DSM portfolio to:
   1. Ensure compliance with the cost-effectiveness requirements of R14-2-2412;
   2. Determine participation rates, energy savings, and demand reductions;
   3. Assess the implementation process for the DSM portfolio;
   4. Obtain information on whether to continue, modify, or terminate a DSM program within a DSM portfolio; and
   5. Determine the persistence and reliability of the affected utility's DSM.

B. An affected utility may conduct evaluation and research, such as market studies, market research, and other technical research, for DSM program planning, product development, and DSM program improvement within a DSM portfolio.

R14-2-2416. Program Administration and Implementation

A. An affected utility may use an energy service company or other external resource to implement a DSM program or DSM measure within a DSM portfolio.

B. The Commission may, at its discretion, establish independent program administrators who would be subject to the relevant requirements of this Article.

R14-2-2417. Leveraging and Cooperation

A. An affected utility shall, to the extent practicable, participate in cost sharing, leveraging, or other lawful arrangements with customers, vendors, manufacturers, government agencies, other electric utilities, or other entities if doing so will increase the effectiveness or cost-effectiveness of a DSM portfolio.

B. An affected utility shall participate in a DSM program with a natural gas utility when doing so is practicable and if doing so will increase the effectiveness or cost-effectiveness of a DSM portfolio.

R14-2-2418. Compliance by Electric Distribution Cooperatives

A. An electric distribution cooperative that is an affected utility shall comply with the requirements of this Section instead of meeting the requirements of R14-2-2404(A) and (B) and R14-2-2405(A).

B. An electric distribution cooperative shall, on June 1 of each odd year, or annually at its election:
   1. File with Docket Control, for Commission review and approval, an implementation plan for each DSM portfolio and programs within a portfolio to be implemented or maintained during the next one or two calendar years, as applicable; and
   2. Submit to the Director of the Commission's Utilities Division an electronic copy of its implementation plan in a format suitable for posting on the Commission's web site.
   3. An implementation plan submitted under subsection (B) shall set forth an energy efficiency goal for each year of at least 75% of the savings requirement specified in R14-2-2404 and shall include the information required under R14-2-2405(B).
   4. Submit annual DSM reports in accordance with the requirements in R14-2-2409.

R14-2-2419. Waiver from the Provisions of this Article

A. The Commission may waive compliance with any provision of this Article for good cause.

B. An affected utility may petition the Commission to waive its compliance with any provision of this Article for good cause.

C. A petition filed pursuant to this Section shall have priority over other matters filed under this Article.