141 FERC ¶ 61,154
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

Arizona Public Service Company Docket No. EC12-106-000

ORDER AUTHORIZING ACQUISITION OF GENERATION FACILITIES

(Issued November 27, 2012)

1. On May 31, 2012, Arizona Public Service Company (APS) filed an application[1] requesting Commission authorization under sections 203(a)(1)(B) and 203(a)(1)(D) of the Federal Power Act (FPA)[2] and Part 33 of the Commission's regulations[3] for APS to acquire Southern California Edison Company's (SoCal Edison) ownership interests in Units 4 and 5 of the Four Corners Power Plant (Four Corners Plant) and associated transmission interconnection facilities and rights (Proposed Transaction). The Commission has reviewed the application under the Commission's Merger Policy Statement.[4] As discussed below, we will authorize the Proposed Transaction as consistent with the public interest.

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[1] APS filed a supplement to its application on July 19, 2012.

[2] 16 U.S.C. § 824b(a)(1) (2006).

[3] 18 C.F.R. pt. 33 (2012).

[4] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (Merger Policy Statement). *See also FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007) (Supplemental Policy Statement). *See also Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). *See also Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006).

I. Background

A. Arizona Public Service Company

2. APS, a wholly-owned subsidiary of Pinnacle West Capital Corporation, is a public utility incorporated in Arizona. APS states that it engages in generation, transmission, distribution and sale of electricity in interstate commerce. APS provides retail electric services to more than one million customers in the Phoenix metropolitan area and throughout Arizona. APS currently owns and/or purchases 8,650 megawatts (MW) of generation capacity in Arizona and the surrounding states. APS is authorized to sell wholesale power at market-based rates in all balancing authority areas during all time periods with the exception of sales delivered in the Phoenix Valley Load Pocket during the months of June, July, and August, which must be made at cost-based rates.[5]

B. Four Corners Power Plant

3. The Four Corners Plant is a coal-fired generating facility located on the Navajo Nation in Fruitland, New Mexico, and is a joint participant project owned by SoCal Edison, APS, Public Service Company of New Mexico (PNM), Salt River Project Agriculture Improvement Power District (Salt River), El Paso Energy Company (El Paso), and Tucson Electric Power Company (Tucson) as tenants in common. APS explains that the Four Corners Plant consists of five generating units. Four Corners Units 1, 2, and 3 are each wholly-owned by APS and have a combined capacity of 560 MW. Four Corners Units 4 and 5 are jointly owned by SoCal Edison, APS, PNM, Salt River, El Paso, and Tucson and have a combined capacity of 1,540 MW. APS states that it operates the Four Corners Plant on behalf of all participants.

4. The Four Corners Plant connects to a 500 kilovolt (kV) transmission line running from Four Corners to Moenkopi, Arizona (Four Corners Moenkopi Line) via three switchyards: one 500 kV switchyard connecting to Unit 5, one 345 kV connecting to Unit 4, and one 230 kV switchyard connecting to Units, 1, 2 and 3. The co-owners of the Four Corners Plant also own these switchyards as tenants in common. The Four Corners Moenkopi Line is owned and maintained by APS and is located within the APS balancing authority area (APS BAA). The California Independent System Operator (CAISO) currently manages SoCal Edison's transmission capacity over the Four Corners Moenkopi Line and provides scheduling information for the line to APS.

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[5] *Arizona Public Service Co.*, Docket Nos. ER99-4124-025 and ER99-4124-026 (Oct. 14, 2010) (delegated letter order).

C. Proposed Transaction

5. APS states that, on November 8, 2010, APS and SoCal Edison entered into a purchase and sale agreement, pursuant to which SoCal Edison will sell and transfer to APS 100 percent of its interests in Four Corners Units 4 and 5 and the associated interests in the 500 kV and 345 kV switchyards. In exchange, APS will pay SoCal Edison $294 million at closing, subject to certain adjustments.

6. Separately, APS states that it plans to retire Four Corners Units 1, 2, and 3 in an effort to meet air quality regulations promulgated by the Environmental Protection Agency. APS is not seeking Commission authorization to retire these units. It states that it included information related to the retirement of these units to provide the Commission with an accurate picture of APS's post-transaction generation portfolio and associated market footprint.

D. Notice of Filing and Responsive Pleadings

7. Notice of the application was published in the *Federal Register*, 77 Fed. Reg. 34,376 (2012), with interventions and comments due on or before June 21, 2012. Iberdrola Renewables, LLC (Iberdrola) filed a timely motion to intervene. SoCal Edison filed a timely motion to intervene and comments.

8. SoCal Edison requests that the Commission accept APS's application because the Proposed Transaction satisfies the requirements of section 203. SoCal Edison explains that it agreed to sell its interest in the Four Corners Facility to satisfy California's law mandating a greenhouse gas emissions performance standard for certain investments in baseload power plants, as well as certain California Public Utilities Commission (California Commission) decisions establishing and implementing the gas emissions performance standards for SoCal Edison. SoCal Edison indicates that the California Commission has found that SoCal Edison's sale of its shares in the Four Corners Facility was reasonable and consistent with the gas emissions performance standard and the California Commission's decisions.

II. Discussion

A. Procedural Issues

9. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[6] the timely, unopposed motions to intervene of Iberdrola and SoCal Edison serve to make them parties to this proceeding.

[6] 18 C.F.R. § 385.214 (2012).

B. Standard of Review Under Section 203

10. Section 203(a)(4) requires the Commission to approve a transaction if it determines that the transaction will be consistent with the public interest.[7] The Commission's analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.[8] Section 203(a)(4) also requires the Commission, before it approves a transaction, to find that the transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest. The Commission's regulations establish verification and informational requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or a pledge or encumbrance of utility assets.[9]

C. Analysis Under Section 203

1. Effect on Competition

a. Applicant's Analysis – Horizontal Market Power

11. APS states that the Proposed Transaction will not have an adverse effect on competition.[10] APS performed a Competitive Analysis Screen, which implements the Delivered Price Test (DPT), using both Economic Capacity (EC) and Available Economic Capacity (AEC) measures. APS states that, because it possesses a significant native load obligation, its analysis focused on the AEC measure.[11] APS identifies non-firm energy and short-term capacity (firm energy) as the relevant products to be analyzed. It also identifies and analyzes the following geographic markets: APS BAA, Phoenix Valley Load Pocket, and the first-tier balancing authority areas of Salt River, CAISO, Los Angeles Department of Water and Power, PNM, PacifiCorp East, Western Area Power Administration – Lower Colorado Region, Tucson Electric Power, and the Imperial Irrigation District.

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[7] 16 U.S.C. § 824(b)(a)(4) (2006).

[8] *See* Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111.

[9] 18 C.F.R. § 33.2(j) (2012).

[10] Application at 13.

[11] *Id.* at 14.

12. APS states that, while it intends to retire Four Corners Units 1 and 2 immediately following the acquisition of SoCal Edison's shares of Four Corners Units 4 and 5, it is unable to fully retire Four Corners Unit 3 until auxiliary steam boilers are installed to support Four Corners Units 4 and 5. APS explains that, until auxiliary steam boilers are installed to support Four Corners Units 4 and 5, Four Corners Unit 3 must remain operational in order to permit APS to start up Four Corners Units 4 and 5 following an outage. Therefore, APS examines the effect of the Proposed Transaction during two periods: the period during which it will have acquired SoCal Edison's share of Four Corners Units 4 and 5 (a total of 739 MW) and retired Four Corners Units 1 and 2 (a total of 340 MW) but has yet to retire Four Corners Unit 3 (220 MW) (Interim Period); and the period during which it will have acquired SoCal Edison's share of Four Corners Units 4 and 5 and retired Four Corners Units 1, 2, and 3 (Post Retirement Period). APS states that, after the retirements of Units 1, 2 and 3, it will own approximately 179 MW of additional generation associated with the Four Corners Plant (739 MW minus 560 MW). However, for the Interim Period, which APS anticipates will be less than two months,[12] APS will own an additional 399 MW of generation (739 MW minus 340 MW).[13]

13. APS's base models assume the prices per MW hour of energy listed in the third column of Table 1 below:

[12] *Id.* at 9 & n.31 (APS anticipates closing on the Proposed Transaction on or about December 1, 2012 and that the Post Retirement Period will begin by February 1, 2013).

[13] Affidavit at Exhibit J-1 at 2.

Table 1

Modeled Price Series				
Definition	**Season/Load Level**	**Applicant's Modeled Price MWh**	**Average 2010 EQR Price ($/MWh) - With Lambda for Missing Values**	**Energy Velocity Avg (2013 forecast)**
Top Load Hour	Summer Super-Peak 1 (S_SP1)	$60.00	$28.4	$43.8
Top 10 percent of peak load hours	Summer Super-Peak 2 (S_SP2)	$40.00	$42.5	$39.6
Remaining peak hours	Summer Peak (S_P)	$28.00	$35.1	$29.0
All off-peak hours	Summer Off-Peak (S_OP)	$26.00	$25.3	$25.9
Top 10 percent of peak load hours	Winter Super-Peak (W_SP)	$27.00	$43.8	$30.9
Remaining peak hours	Winter Peak (W_P)	$23.00	$38.4	$26.1
All off-peak hours	Winter Off-Peak (W_OP)	$21.00	$29.8	$23.7
Top 10 percent of peak load hours	Shoulder Super-Peak (SH_SP)	$35.00	$35.4	$31.7
Remaining peak hours	Shoulder Peak (SH_P)	$25.00	$32.0	$25.7
All off-peak hours	Shoulder Off-Peak (SH_OP)	$23.00	$25.4	$22.8

Source: Exhibit J-1 at 22 and Applicant's Workpapers[14]

14. APS states that this price series is derived primarily from an analysis of historical Electric Quarterly Report (EQR) data with system lambda used to fill in the missing hours adjusted for changes in fuel costs and a forecast of 2013 prices from *Ventyx*.[15] It also tested the sensitivities of these modeled prices with a 10 percent increase and a 10 percent decrease in price to capture a range of prices from $19/MWh to $66/MWh.[16]

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[14] WKP – APS BAA EQR Prices, EQRs Price Summary.

[15] Affidavit at Exhibit J-1 at 22.

[16] *Id.* at 24.

15. APS estimates load based on FERC Form No. 714 from 2010 and escalated to year 2013 based on the estimates contained in those forms. It uses its own Integrated Resource Plan for 2012 to determine peak load and energy requirements[17] and relies on the most recent Simultaneous Transmission Import Limit (SIL) Order accepted by the Commission. For the APS BAA, APS uses the SIL values accepted by the Commission in the most recent triennial filing but then makes adjustments to reflect a forward looking snapshot.[18]

i. Interim Period

16. APS evaluates two scenarios for the Interim Period: the first in which it would be unable to import all of its ownership at the Four Corners Plant into the APS BAA, which its acquired ownership would entitle it to, because of transmission constraints (Constrained Scenario), and a second scenario in which all of the operating generation from Four Corners Units 3, 4, and 5 owned by APS may be delivered into the relevant geographic market (Unconstrained Scenario). APS states that its net increase in generation in the Interim Period when limited by transmission constraints is approximately 100 MW.[19] When APS incorporates all of the APS-owned generation at the Four Corners Plant into its market analysis for the APS BAA, the net increase in generation is 399 MW.[20] APS states that it confines its analysis to the winter months because the Interim Period will not continue beyond the winter period.

17. APS explains that it is appropriate to consider the 100 MW increase in deliverable capacity because there is insufficient transmission capacity available to bring into the APS BAA both the shares of Four Corners Units 3, 4, & 5 that it currently owns and the additional shares of Four Corners Units 4 & 5 that it would acquire from SoCal Edison.[21] APS further explains that, due to such transmission limits, it would utilize its shares of Four Corners Units 4 and 5, rather than Unit 3, to serve its load obligations in Arizona (because Units 4 and 5 are relatively more efficient units), and that any sales from Four Corners Unit 3 during the Interim Period will be to markets outside of the APS BAA. APS states that, in the Constrained Scenario, there are no screen violations using the base price assumptions or when prices are reduced five or 10 percent.[22] APS states that when prices are increased five percent, there is one screen failure where it has a market share of

[17] *Id.*

[18] *Id.* at n.29.

[19] Application at 16.

[20] *Id.* at 15.

[21] *Id.* at 16.

[22] Affidavit at Exhibit J-1 at 28.

15 percent, the market is moderately concentrated, and the Herfindahl-Hirschman Index (HHI) rises by 101 points.[23] When prices are increased by 10 percent, there are two screen failures where APS has a market share of 22 percent, and the HHI rises by 127 and 213 points in a moderately concentrated market.[24] A summary of APS's DPT results, in which screen failures occur, is set forth in Table 2 below.

Table 2

Winter Season, Interim Period with ~100 MW capacity included				
Base				
Season/Load Level	Price	Mkt Share	HHI	HHI Chg
W_SP	$ 27	12%	1,800	10
W_P	$ 23	0%	1,689	14
W_OP	$ 21	0%	1,627	-
Prices + 5%				
W_SP	**$ 28**	**15%**	**1,724**	**101**
W_P	$ 24	0%	1,415	20
W_OP	$ 22	0%	1,477	5
Prices + 10%				
W_SP	**$ 30**	**22%**	**1,676**	**213**
W_P	**$ 25**	**16%**	**1,715**	**127**
W_OP	$ 23	0%	1,489	15

Source: Exhibit J-5

[23] The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Markets in which the HHI is less than 1,000 points are considered to be unconcentrated; markets in which the HHI is greater than or equal to 1,000 but less than 1,800 points are considered to be moderately concentrated; and markets in which the HHI is greater than or equal to 1,800 points are considered to be highly concentrated. In a horizontal merger, an increase of more than 50 HHI points in a highly concentrated market or an increase of 100 HHI points in a moderately concentrated market fails its screen and warrants further review. Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,129; s*ee Order Reaffirming Commission Policy and Terminating Proceeding*, 138 FERC ¶ 61,109 (2012) (affirming the Commission's use of the thresholds adopted in the Merger Policy Statement).

[24] Affidavit at Exhibit J-1 at 28.

18. APS states that the screen failures that arise in the Interim Period under the Constrained Scenario are non-systematic, occasional screen failures that do not indicate cause for concern when the competitive facts are considered.[25] APS explains that the Commission has approved section 203 applications even though there were screen violations in cases where: (1) the failures occurred in off-peak periods when the applicants had relatively low market shares; (2) the withholding strategy could be detected by market monitors and the generation units at issue were baseload units that would not be profitable to withhold; and (3) the applicants lacked the ability to withhold output due to provider of last resort and long-term power sales obligations.[26] APS states that virtually all of these factors are present in this case. APS states that the only relevant screen failures occur during off-peak seasons, the coal-fired generation being acquired is efficient and operates as baseload generation, and APS retains significant load and reliability obligations which are the basis for the Proposed Transaction.[27]

19. APS also argues that the Proposed Transaction will not eliminate a significant competitor in the APS BAA. Evaluating EQR data, SoCal Edison's sales totaled one percent of total deliveries at the trading hub, SoCal Edison had no sales into the APS BAA, and made less than 10,000 MWh sales to APS at the Four Corners Plant, accounting for less than one percent of total sales.[28] Additionally, APS states that it is a net purchaser in the market which gives it little incentive to increase price in short-term energy markets.[29]

20. APS also analyzes the Proposed Transaction during the Interim Period assuming that APS will be able to deliver all of the capacity that it will own at the Four Corners Plant to the APS BAA; that is, it assumes there are no transmission constraints. APS states that there is a base case screen failure under this assumption during the winter super-peak period, with an HHI change of 54 in a highly concentrated market.[30] APS states that this screen failure persists when prices are increased by 5 percent and that there is an additional screen failure during the winter peak period when prices are

[25] Application at 18.

[26] *Id.* n.37 (citing *Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109, at P 37 (2012)).

[27] *Id.* n.37.

[28] *Id.* at 19.

[29] *Id.*

[30] *Id.* at 19-20; Affidavit at Exhibit J-1 at 28-29.

increased by 10 percent,[31] as shown in Table 3 below. APS does not fail any screens when prices are reduced by five or 10 percent.

Table 3

Winter Season, Interim Period with all acquired capacity included				
Base				
Season/Load Level	Price	Mkt Share	HHI	HHI Chg
W_SP	**$ 27**	**15%**	**1,844**	**54**
W_P	$ 23	0%	1,689	14
W_OP	$ 21	0%	1,627	-
Prices + 5%				
W_SP	**$ 28**	**18%**	**1,792**	**169**
W_P	$ 24	0%	1,415	20
W_OP	$ 22	0%	1,477	5
Prices + 10%				
W_SP	**$ 30**	**24%**	**1771**	**308**
W_P	**$ 25**	**19%**	**1,794**	**206**
W_OP	$ 23	0%	1,489	15

Source: Exhibit J-6

21. APS explains that, despite multiple screen failures during the Interim Period under both the Constrained Scenario and the Unconstrained Scenario sensitivity analysis, it has no incentive or ability to exercise horizontal market power.[32] First, while the Proposed Transaction will provide APS with an additional 340 MW of baseload generation for a period of approximately two months, APS states that jointly-owned facilities, such as the Four Corners Plant, are unlikely to be used to withhold capacity

[31] Application at 20.

[32] *Id.*

from the market because the other owners would be immediately aware of and impacted by any withholding strategy. Second, APS states that because essentially all wholesale customers within the APS BAA are currently served under long-term arrangements, APS has very little incentive to exercise market power within the APS BAA. Third, as of July 1, 2012, APS's Power Supply Adjustment Mechanism obligates APS to credit retail customers with 100 percent of revenue APS earns from wholesale sales of power to non-native load customers. APS asserts that the "non-existent" financial benefit to APS from such sales reduces APS's incentive to manipulate market prices.[33]

22. APS argues that in the absence of Commission approval, should the Four Corners Plant co-owners decide to close the plant, APS would have no choice but to either enter into firm power purchase agreements with third parties, or construct new generating facilities to obtain sufficient energy to serve its customers. APS states that if either of those steps were taken, APS's market share would be the same as it would be under the Proposed Transaction, but APS's customers would be required to bear higher costs.[34]

23. APS states that if, notwithstanding the foregoing, the Commission concludes that the Proposed Transaction presents competitive concerns, APS would be willing to effectively retire Four Corners Unit 3 at the same time that Four Corners Units 1 and 2 are retired. APS would commit to run Four Corners Unit 3 only when needed to provide auxiliary steam supply necessary to start up Four Corners Units 4 and/or 5, and, in any such instances, would commit that the combined output of Units 3, 4 and 5 would not exceed APS's share of the total capacity of Units 4 and 5 (970 MW). Once auxiliary steam boilers are installed to support Four Corners Units 4 and 5, APS would fully retire Four Corners Unit 3.[35] APS commits to notify the Commission that Four Corners Unit 3 has been retired in an informational filing to be submitted within 30 day of Four Corners Unit 3's retirement.[36]

ii. <u>Post Retirement Period</u>

24. APS reports that for the base case using the AEC measure in the Post Retirement Period, the Proposed Transaction results in a change in HHI of no more than 34 points in a moderately concentrated market. Its base case analysis demonstrates that APS passes the Commission's screens.[37] APS also passes the Commission's screens when prices

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[33] *Id.* at 22.

[34] *Id.*

[35] *Id.* at 27 & n.28.

[36] *Id.* at n.59.

[37] Affidavit at Exhibit J-1 at 24.

are raised five percent from its base model and when prices are reduced by five or 10 percent.

25. When prices are raised by 10 percent, APS fails screens in the summer peak and winter super-peak periods, with HHI changes of 106 and 113, respectively, in a moderately concentrated market. However, APS argues that the screen failures are not a cause for concern because they are non-systematic and APS does not have a dominant market share. APS explains that the screen violation in the winter super-peak results from that period being characterized by low load levels where for example the load is 10 percent lower than the summer off-peak period.[38]

Table 4

Post Retirement Period				
Base Case				
Season/Load Level	Price	Mkt Share	HHI	HHI Chg
S_SP1	$60	8%	1,053	-2
S_SP2	$40	7%	1,109	-22
S_P	$28	1%	1,303	-30
S_OP	$26	16%	1,295	34
W_SP	$27	8%	1,770	-20
W_P	$23	0%	1,684	9
W_OP	$21	0%	1,627	-
SH_SP	$35	0%	1,141	-4
SH_P	$25	0%	1,090	0
SH_OP	$23	0%	1,282	20

Prices + 5%				
Season/Load Level	Price	Mkt Share	HHI	HHI Chg
S_SP1	$63	8%	1,053	-2
S_SP2	$42	9%	1,068	3
S_P	$29	19%	1,240	76
S_OP	$27	16%	1,205	57

[38] *Id.* at 27.

W_SP	$28	11%	1,663	39
W_P	$24	0%	1,422	26
W_OP	$22	0%	1,475	3
SH_SP	$37	0%	1,043	-1
SH_P	$26	10%	1,210	-13
SH_OP	$24	9%	1,017	11

Post Retirement Period				
Prices + 10%				
Season/Load Level	Price	Mkt Share	HHI	HHI Chg
S_SP1	$66	8%	1,053	-2
S_SP2	$44	9%	1,058	5
S_P	**$31**	**23%**	**1,313**	**106**
S_OP	$29	18%	1,188	70
W_SP	**$30**	**19%**	**1,576**	**113**
W_P	$25	13%	1,647	59
W_OP	$23	0%	1,489	15
SH_SP	$39	1%	1,036	-12
SH_P	$28	12%	1,134	14
SH_OP	$25	18%	1,227	49

Source: Exhibit J-4

26. APS cites several mitigating factors as to why the screen failures are not indicative of a concern. First, the largest violation occurs during an off-peak season (winter). Second, the generation being acquired has low dispatch costs and operates as baseload generation which is not readily susceptible to strategic dispatch. Third, APS retains significant load and reliability obligations which are driving the need for the Proposed Transaction.[39] APS also reiterates that the Proposed Transaction would not create the ability to exercise market power because: the Four Corners Facility (i.e., Four Corners Units 4 and 5) will be jointly owned; all wholesale customers are served under long-term contracts; and APS must credit retail customers with 100 percent of the revenue from wholesale sales to non-native load customers.[40]

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[39] *Id.*

[40] Application at 25.

27. APS states that the Phoenix Valley Load Pocket region was deemed a relevant geographic market in APS's prior triennial market power update. APS states that the Phoenix Valley Load Pocket is a potential market only during the summer season, when historically, there was not sufficient import capability to serve loads in the region without running some amount of local generation.[41] Therefore, APS examined the effect of the Proposed Transaction on market concentration in the Phoenix Valley Load Pocket submarket only for the Post Retirement Period because the Interim Period does not include summer months.[42]

b. Commission Determination

28. We agree with APS's assessment that a focus on the AEC measure is more relevant to assessing the competitive impact of the Proposed Transaction than EC in the APS BAA because of APS's significant native load obligation, with no foreseeable prospect of that obligation being lifted.[43] Using APS's analysis, the Proposed Transaction fails the Commission's market concentration screens in the Interim Period, both under the Unconstrained Scenario (during the winter super-peak, see Table 3), when testing sensitivities for small variations (here, of +/- 5 or 10 percent) in actual and/or estimated prices, and in the Constrained Scenario (during the winter peak and super-peak, see Table 2 and Table 3). APS also fails the Commission's screens in the Post Retirement Period when prices are increased by 10 percent (during the summer peak and winter super-peak, see Table 4). However, as discussed below, when considering the other relevant factors, we find that the Proposed Transaction will not have an adverse effect on horizontal market power. We make this finding in spite of certain shortcomings in the DPT results presented in the Application, which include: the lack of support for using a blend of system lambda and EQR data in calculating the price series,[44] and the use of one year rather than two years of market price data.[45]

29. APS's DPT analysis relied on price data that we find was not based on actual prices, nor projected prices that are properly justified in certain seasons. While the modeled prices covered a range of prices that actually occurred and may be appropriate if

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[41] Affidavit at Exhibit J-1 at 30.

[42] Application at 23.

[43] *See, e.g.*, *Great Plains Energy Inc.*, 121 FERC ¶ 61,069, at P 34 (2007). *See also Nevada Power Co.*, 113 FERC ¶ 61,265, at P 15 (2005).

[44] 18 C.F.R. § 33.3(d)(6) (The applicant may provide suitable proxies for market prices if actual market prices are unavailable but such prices must be supported).

[45] *Id.* (The applicant must provide, for each relevant product and destination, market prices for the most recent two years).

properly justified, as the table below shows, in certain periods prices are adjusted by a greater degree than is explained in the Application. Specifically, in certain seasons and under certain load conditions, the 10 percent price sensitivity analysis does not cover the complete range of prices.

Table 5

Season/Load Level	Adjusted for 2013 EQR Price ($/MWh) - With Lambda for Missing Values	Energy Velocity Avg (2013 forecast)	Applicant's Modeled Price MWh	Average of Forecast Prices	Price Difference of model price from average Forecast price
Summer Super-Peak 1 (S_SP1)	**$ 22.87**	**$ 43.8**	**$ 60**	**$ 33**	**44%**
Summer Super-Peak 2 (S_SP2)	$ 34.28	$ 39.6	$ 40	$ 37	8%
Summer Peak (S_P)	$ 27.41	$ 29	$ 28	$ 28	-1%
Summer Off-Peak (S_OP)	**$ 19.81**	**$ 25.9**	**$ 26**	**$ 23**	**12%**
Winter Super-Peak (W_SP)	**$ 29.85**	**$ 30.9**	**$ 27**	**$ 30**	**-13%**
Winter Peak (W_P)	**$ 26.42**	**$ 26.1**	**$ 23**	**$ 26**	**-14%**
Winter Off-Peak (W_OP)	$ 20.49	$ 23.7	$ 21	$ 22	-5%
Shoulder Super-Peak (SH_SP)	$ 31.38	$ 31.7	$ 35	$ 32	10%
Shoulder Peak (SH_P)	$ 27.89	$ 25.7	$ 25	$ 27	-7%
Shoulder Off-Peak (SH_OP)	$ 22.52	$ 22.8	$ 23	$ 23	1%

Source: Applicant's Workpapers & Staff Calculations[46]

30. As explained previously, the Commission prefers the use of actual market prices rather than price proxies such as system lambda.[47] The Commission confirmed its preference for using actual market prices in *Duke Power*,[48] where, citing its regulations,

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[46] *See* WKP – APS BAA EQR Prices, EQRs Price Summary. The first four columns of the table reflect data from Applicant's Workpapers. The last two columns are Staff Calculations.

[47] *Duke Energy Corporation*, 136 FERC ¶ 61,245 at P 121 (2011).

[48] 111 FERC ¶ 61,506 (2005).

the Commission rejected the use of system lambda where actual prices were available from EQR data.[49] APS neither explains why EQR data is insufficiently robust to create reliable price estimates nor why system lambda is an appropriate proxy for hours where no price data is available. APS also uses only one year of EQR data whereas two years of data, which is required under the Commission's regulations,[50] may have provided a more robust price series. As the Commission recently explained, the focus should be on whether there is sufficient coverage of transactional data for each season/load period, and not on each individual hour within a season/load period. Thus, even if a particular hour of the year has no transactions, many of the other hours in the season/load period to which that hour belongs have transactions and many include multiple transactions per hour.[51] These differences in analysis can materially affect the results of the DPT and therefore may affect whether the Proposed Transaction passes the Commission's HHI thresholds. Despite these shortcomings in the APS DPT, when the EQR price data submitted by Applicants is analyzed, without system lambda adjustments, to cross check the results of this DPT, we find that the study corrected in this manner would not produce systematic screen failures in additional seasons/load periods, or in significantly greater magnitudes, than those identified above. Therefore, we find that these corrected results, where Applicants fail screens, are offset by the specific facts of the instant case. As discussed below, we find that the screen failures do not indicate that the Proposed Transaction will result in an adverse effect on competition in the APS BAA.

31. In Order No. 642, the Commission stated it will look beyond the HHI screens if a transaction proposed under section 203 does not meet the HHI thresholds set forth in the Merger Policy Statement. The Commission clarified that applicants with screen failures could address market conditions beyond the change in HHI "such as demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved."[52] In the Supplemental Policy Statement, the Commission stated that "in horizontal mergers, if an applicant fails the Competitive Analysis Screen (one piece of the Appendix A analysis), the Commission's analysis focuses on the merger's effect on the merged firm's <u>ability</u> and <u>incentive</u> to withhold output in order to drive up the market price."[53]

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[49] *Duke Power*, 111 FERC ¶ 61,506 at P 31.

[50] 18 C.F.R. § 33.3(d)(6).

[51] *Duke Energy Corporation*, 136 FERC ¶ 61,245 at P 126.

[52] *Id*.

[53] Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 at P 60 (emphasis in original).

32. We find that even though APS did not adequately support the departure from the Commission approved (preferred) methodology in its DPT analysis, and failed to meet the requirement for providing market price data, even if we assume a scenario where APS fails the competitive analysis screen in some additional load/season periods, APS has presented several factors specific to the Proposed Transaction which indicate that there will not be an ability and incentive to withhold output, as discussed below, and therefore the transaction will not have an adverse impact on competition based on the unusual circumstances present here.

33. Specifically, we find that for the following reasons the Proposed Transaction will not adversely affect competition in either the Interim or the Post-Retirement periods, even though it causes HHI screen failures in a few seasons/load periods. First, the Proposed Transaction involves the purchase of baseload coal-fired capacity that will be jointly owned. Baseload capacity is difficult to withhold, as is capacity that is jointly owned, which undermines APS's ability to withhold even if it were inclined to do so. Since baseload capacity is also typically uneconomic to withhold, this would reduce any incentive that APS might have to withhold.[54] Second, the capacity being acquired by APS exceeds the amount of retiring capacity, and thus there is an increase in market concentration as measured by HHIs. The Four Corners Plant is economic to run during all periods so the increase in APS's long-term controlled capacity could hypothetically give APS the incentive to withhold other intermediate- or peaking- capacity to increase prices. However, APS serves its wholesale customers under long-term arrangements which do not allow APS to benefit from temporary price increases because APS has the obligation to deliver power at the contract rate to customers regardless of the prevailing price. The Commission has found that appropriately structured long-term sales agreements, among other things, may mitigate market power.[55] Additionally, the provision in APS's Power Supply Adjustment Mechanism, which obligates APS to credit

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[54] *See FirstEnergy Corp.*, 133 FERC ¶ 61,222, at P 50 (2010) (finding that withholding baseload generation capacity would not increase prices enough to offset lost revenue). *See also Wisconsin Energy Corporation, Inc.*, 83 FERC ¶ 61,069, at 61,358 (1998) (finding the ability to exercise market power is tempered by the fact that the transmission facilities used to deliver power are jointly-owned facilities).

[55] *See Exelon Corporation*, 138 FERC ¶ 61,167, at P 101 (2012) (finding a long-term sale serves to counter the incentive applicants may have to raise prices); *see also Duke Energy Corporation*, 139 FERC ¶ 61,194, at P 85 (2012) (finding long-term sales as part of an interim mitigation package mitigate adverse competitive effects); and *Ameren Service Co.*, 101 FERC ¶ 61,202, at P 43 (2002) (finding extending contracts to wholesale customers a mitigating factor to combat interim anticompetitive by maintaining the status quo with respect to power supply costs).

retail customers with 100 percent of revenue earned from wholesale sales of power to non-native load customers, reduces APS's incentive to manipulate market prices through exerting market power because APS will not receive any benefit from the additional revenue that might result if APS were to manipulate market prices. All such revenue would have to be credited to retail customers under the Power Supply Adjustment Mechanism. The above factors would reduce any incentive that APS might have to withhold, and the contractual obligations that APS has to perform under these PPAs (and the legal and monetary consequences it faces if it does not) mean that it would have little practical ability to withhold capacity.

34. Third, we are persuaded that the Proposed Transaction will not result in the elimination of a competitor, since SoCal Edison has not generally sold into the APS BAA, and that during the Post Retirement Period, APS's net generation capacity will only result in a 179 MW increase capacity in a market with 8,382 MW of peak load and reserve requirements.

35. Finally, we note that for both the Interim and the Post-Retirement Periods none of the screen failures are systematic, they are all small in magnitude, and the Interim screen failures were of short duration (lasting only two months) and not at the time of the system peak.

36. For the reasons above we find that the HHI screen failures do not indicate that the Proposed Transaction will result in an adverse effect on competition in the APS BAA. Accordingly, we do not believe that there is a need to condition our approval on APS's proposed commitment to limit the output of Four Corners Units 3, 4 and 5 during the Interim Period. We direct APS to notify the Commission that Four Corners Unit 3 has been retired within 30 days of the date of retirement.

c. Applicant's Analysis – Vertical Market Power

37. APS states that the Proposed Transaction does not raise any competitive concerns with regard to vertical market power. APS explains that the Proposed Transaction will not result in APS acquiring a new transmission system or substantial transmission system assets and that APS already owns and operates its transmission system pursuant to a Commission-approved open access transmission tariff (OATT).[56] Additionally, APS states that all of its wholesale buyers either own the transmission needed to serve their loads or have firm transmission rights to access the regional wholesale market. Moreover, APS states that there is no material change in APS's ability or incentive to exercise vertical market power as a result of the Proposed Transaction because the Proposed Transaction creates no additional incentive to foreclose rival generators through

[56] Application at 28.

transmission. APS also states that the Proposed Transaction does not have any effect on essential resources which could erect barriers to market entry by competing suppliers.[57] APS states that it does not own or control inputs to generation that would form a basis that APS could raise barriers to entry. APS states that it does not own or control any intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, or sources of coal supplies or barges.[58]

d. Commission Determination

38. As the Commission has previously found, transactions that combine electric generation assets with inputs to generating power (such as natural gas, transmission, or fuel) can harm competition if the transaction increases a firm's ability or incentive to exercise vertical market power in wholesale electricity markets. For example, by denying rival firms access to inputs or by raising their input costs, a firm created by the transaction could impede entry of new competitors or inhibit existing competitors' ability to undercut an attempted price increase in the downstream wholesale electricity market.[59]

39. The Commission finds that the Proposed Transaction does not raise any vertical market power concerns. APS's transmission lines are subject to an OATT, and the only transmission facilities involved in the Proposed Transaction are limited interconnection facilities associated with the Four Corners Plant. Additionally, APS has stated that the Proposed Transaction will not materially change its ability or incentive to exercise vertical market power. Likewise, APS states that it does not own or control inputs to generation. Therefore, the Proposed Transaction will not increase its ability to erect barriers to entry.

2. Effect on Rates

a. Applicant's Analysis

40. APS states that there is no basis for concern regarding the rates that will be charged to wholesale power or transmission customers because it is not seeking to recover the cost of acquiring SoCal Edison's ownership interests in Four Corners Units 4 and 5 through its wholesale power or transmission rates. Instead, APS intends to recover the cost of acquiring SoCal Edison's ownership interests in Four Corners Units 4 and 5 through its retail rates.[60] As part of its application for approval of the Proposed

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[57] *Id.* at 29.

[58] Affidavit at Exhibit J-1 at 33.

[59] *Duke Energy Corp.*, 136 FERC ¶ 61,245, at P 160 (2011).

[60] Application at 29.

Transaction filed with the Arizona Corporation Commission (Arizona Commission), APS requested and was granted, an accounting order authorizing APS to defer and capitalize for future recovery through its retail rates all non-fuel costs of owning, operating and maintaining the acquired interests in Four Corners Units 4 and 5.[61] Therefore, APS states that the Proposed Transaction will have no adverse impact on the rates charged to APS's wholesale power or transmission customers.

b. Commission Determination

41. Under the circumstances presented, the Commission finds that the Proposed Transaction will not have an effect on rates that is adverse to the public interest. APS indicates that it intends to recover the cost of the Proposed Transaction solely through its retail rates, which the Arizona Commission has already approved, and we accept APS's commitment that the cost of acquiring SoCal Edison's ownership interests in Four Corners Units 4 and 5 will not be recovered through its wholesale power or transmission rates. We note that no parties have argued that the Proposed Transaction will adversely affect rates.

3. Effect on Regulation

a. Applicant's Analysis

42. APS states that the Proposed Transaction will not impair the ability of the Commission or the Arizona Commission to regulate it. The Commission will continue to exercise the same jurisdiction over sales of electricity at wholesale by APS after the Proposed Transaction is consummated. APS states that no facilities will be removed from the Commission's jurisdiction. APS states that the Proposed Transaction has received prior approval by the Arizona Commission, which will have jurisdiction over APS's use of Units 4 and 5 of the Four Corners Plant to serve retail customers after the Proposed Transaction, and by the California Commission.[62] Additionally, APS states that the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of

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[61] *Id.* at 29-30 (citing *In the Matter of the Application of Arizona Public Services Company for Authorization for the Purchase of Generating Assets from Southern California Edison and for an Accounting Order*, Decision No. 73130, ACC Docket No. E-01345A-10-0474).

[62] *Id.* at 2, 30.

1976[63] has been terminated by the Department of Justice and the Federal Trade Commission.[64]

b. Commission Determination

43. We find no evidence that either state or federal regulation will be impaired by the Proposed Transaction. The Commission's review of a transaction's effect on regulation focuses on ensuring that it does not result in a regulatory gap at the federal or state level.[65] We find that the Proposed Transaction will not create a regulatory gap at the federal level because the Commission will retain its regulatory authority over the companies after the Proposed Transaction is consummated. The Commission stated in the Merger Policy Statement that it ordinarily will not set the issue of the effect of a transaction on state regulatory authority for a trial-type hearing where a state has authority to act on the transaction. However, if the state lacks this authority and raises concerns about the effect on regulation, the Commission stated that it may set the issue for hearing, and that it will address such circumstances on a case-by-case basis.[66] We note that neither the Arizona Commission nor the California Commission has requested that the Commission address the issue of the effect of the Proposed Transaction on state regulation.

4. Cross-Subsidization

a. Applicant's Analysis

44. APS contends that the Proposed Transaction will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of assets of a traditional public utility that has captive customers or that owns or provides transmission service over jurisdictional facilities for the benefit of an associate company. Specifically, APS verifies that, based on the facts and circumstances known to it or that are reasonably foreseeable, the Proposed Transaction will not result in, at the time of the transaction or in the future: (1) any transfer of facilities between a traditional public utility associate company that has captive ratepayers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company; (2) any new issuance of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for

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[63] 15 U.S.C. § 18a (2006).

[64] APS July 19, 2012 Supplemental Filing at 2.

[65] Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

[66] *Id*. at 30,125.

the benefit of an associate company;[67] (3) any new pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; or (4) any new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.[68]

b. Commission Determination

45. Based on the representations as presented in the Application, we find that the Proposed Transaction will not result in cross-subsidization or the pledge or encumbrance of utility assets for the benefit of an associate company.

5. Other Issues

46. APS shall account for the transaction in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold, of the Uniform System of Accounts (USofA). APS shall submit its final accounting entries within six months of the date that the transaction is consummated, and the accounting submissions shall provide all the accounting entries and amounts related to the transfer along with narrative explanations describing the basis for the entries.

47. Information and/or systems connected to the bulk power system involved in this transaction may be subject to reliability and cyber security standards approved by the Commission pursuant to FPA section 215. Compliance with these standards is mandatory and enforceable regardless of the physical location of the affiliates or investors, information databases, and operating systems. If affiliates, personnel or investors are not authorized for access to such information and/or systems connected to the bulk power system, a public utility is obligated to take the appropriate measures to deny access to this information and/or the equipment/software connected to the bulk power system. The mechanisms that deny access to information, procedures, software, equipment, and the like, must comply with all applicable reliability and cyber security standards. The Commission, North American Electric Reliability Corporation, or the

[67] APS states that, although it may periodically issue new securities that will support the financing of the Four Corners Plant acquisition, other near-term resource additions, and/or for general corporate purposes, any such issuances will not be for the benefit of an associate company.

[68] Application at Exhibit M.

relevant regional entity may audit compliance with reliability and cyber security standards.

The Commission orders:

(A) The Proposed Transaction is hereby authorized, as discussed in the body of this order.

(B) APS is directed to notify the Commission that Four Corners Unit 3 has been retired within 30 days of the date of retirement, as discussed in the body of this order.

(C) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates, or determinations of cost, or any other matter whatsoever now pending or which may become before the Commission.

(D) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted.

(E) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate.

(F) APS shall make appropriate filings under section 205 of the FPA, as necessary, to implement the Proposed Transaction.

(G) APS must inform the Commission within 30 days of any material change in circumstances that would reflect a departure from the facts the Commission relied upon in authorizing the Proposed Transaction.

(H) APS shall notify the Commission within 10 days of the date on which the Proposed Transaction is consummated.

(I) To the extent that the Proposed Transaction affects any entity that is required to keep its books and records in accordance with the USofA, that entity must account for the Proposed Transaction in accordance with Electric Plant Instruction No. 5 and Account 102, Electric Plant Purchased or Sold. The entity shall submit its final accounting entries within six months from the date the Proposed Transaction is consummated, and the accounting submission shall provide all the accounting entries and amounts related to the Proposed Transaction along with narrative explanations describing the basis for the entries. If the entries are recorded after six months from the date the Proposed Transaction was consummated, the entity must file those entries with the Commission within 60 days from the date of recording such entries.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.
Deputy Secretary