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SIERRA CLUB
FOUNDED 1892

Via Personal Delivery & E-Filing

Jan Sanders, Secretary
Arkansas Public Service Commission
1000 Center Street
PO Box 400
Little Rock, AR 72203

March 14, 2013

Re: PSC Docket No. 12-008-U – HSPI Second Supplemental Rebuttal Testimony and Exhibit of Paul Chernick on Behalf of the Sierra Club

Dear Ms. Sanders:

Please find enclosed an original and three copies of the HSPI/Confidential Second Supplemental Rebuttal Testimony of Paul Chernick and Confidential Exhibit PC-F7 on behalf of the Sierra Club in Docket No. 12-008-U to be filed under seal in this docket pursuant to Protective Order No. 1. Redacted versions of these documents, as well as public Sierra Club exhibits, have been submitted through the Electronic Filing System on this day.

Please let me know if you need any additional documents from me or if you have any questions. Thank you.

Sincerely,

/s/ Derek Nelson

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STATE OF ARKANSAS

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of Southwestern Electric	**)**	
Power Company's Petition for a Declaratory	**)**	**Docket No. 12-008-U**
Order Finding that Installation of	**)**	
Environmental Controls at the Flint Creek	**)**	
Power Plant Is In the Public Interest	**)**	

SECOND SUPPLEMENTAL REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE SIERRA CLUB

Resource Insight, Inc.

MARCH 14, 2013

Redacted Version

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I. Introduction

Q: Are you the same Paul Chernick who filed direct and rebuttal testimony in this docket?

A: Yes.

Q: To which testimony will you be responding?

A: I respond to aspects of the January 11, 2013 direct testimony of SWEPCo witnesses Venita McCellon-Allen and Lanny Nickell, filed pursuant to Commission Order No. 10.[1]

Q: How does SWEPCo's evidence in this new round of testimony differ from its sur-surrebuttal testimony?

A: This new evidence adds very little substance to the record, mostly repeating claims that SWEPCo made earlier in the process. The major change is that SWEPCo has abandoned any technical claim that transmission would be insufficient to serve northwest Arkansas. The new testimony focuses on three claims:

- In the absence of the environmental retrofit projects that are the subject of this proceeding, Flint Creek would need to shut down by April 2015.
- Building transmission to serve northwest Arkansas would take some years beyond 2015, during which time reliability in northwest Arkansas would be very poor.

[1]This direct testimony was filed eleven months after the rest of the utilities' direct testimony. The utilities requested the opportunity to supplement the record following the close of the record and submission of briefs.

- Purchasing generation resources to replace Flint Creek would take several years, during which time SWEPCo, PSO and other utilities in the AEP sub-region would suffer some sort of consequences.

Q: How has SWEPCo's position changed over time regarding the role of transmission into northwest Arkansas as an alternative to Flint Creek?

A: During this proceeding SWEPCo has taken several different positions:

- In Hassink Direct at 8, SWEPCo presented a greenfield combined-cycle plant combined with new transmission, capacitor banks, and VAR compensators in northwest Arkansas as a viable alternative to Flint Creek as early as March 2016.[2] SWEPCo's economic analyses assumed that the line would be required only if Flint Creek were retired and no new generation was built in northwest Arkansas.
- In rebuttal, SWEPCo Witness Bennett took the position that regardless of the fate of Flint Creek, "enhancing the transmission system is a must" for northwest Arkansas (Bennett Rebuttal at 30).
- In SWEPCo's sur-surrebuttal testimony, Witness Hassink continued to present transmission as a viable alternative to Flint Creek, although he pointed out that transmission energy losses would tend to be higher with expanded transmission rather than generation in northwest Arkansas. Witness Hassink raised the concern that studying, permitting, and constructing new transmission would require four to seven years if the various pre-construction activities were undertaken sequentially (Hassink Sur-Surrebuttal at 5), which Witness Bennett restated as five to seven years (Bennett Sur-Surrebuttal at 8). Witness Bennett (Sur-Surrebuttal at

[2]Specifically, a 70-mile 345-kV line from Fort Smith to Chamber Springs, plus 100 MVAR of static VAR compensators and 170 MVAR of conventional capacitor banks and reactors.

7) also asserted that Mr. Hassink's sur-surrebuttal testimony showed that "a transmission system solution alone cannot solve the immediate issue at hand," even though Mr. Hassink's testimony does not make any such demonstration.[3]

- In its January 2013 testimony, SWEPCo drops the claim that transmission would not be adequate to serve northwest Arkansas for the long-term. Instead the Company asserts that there would be short-term reliability issues while the transmission upgrades are being put in place.

Q: What topics will you address in this rebuttal?

A: I respond to the following three topics discussed at length in SWEPCo's January 11, 2013, testimony:

- the deadline for shutting down Flint Creek if it is not retrofitted to comply with the EPA's Mercury and Air Toxics Standards (MATS).
- the timeline for bringing new transmission and generation resources on to replace Flint Creek.
- the implications of operating without Flint Creek, prior to construction of new generation and transmission resources.

I do not respond to the less-substantive testimony of SWEPCo witness Mike Malone (who simply repeats concerns about reliability based on other witnesses' testimony) and AECC witness Duane Highley (who primarily discusses AECC's lack of interest in co-owning Flint Creek if it is converted to

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[3]The transmission witness for AECC asserted that no amount of transmission into northwest Arkansas would be adequate without baseload generation in northwest Arkansas (Bittle Sur-Surrebuttal at 5), although its witness later admitted that his difference of opinion with SWEPCo's transmission witness, Mr. Hassink, was merely "philosophical" (Tr. 1672:6-18).

gas). Witness Highley also estimates that retirement of Flint Creek would require AECC to

> record any remaining net plant value as a loss on its income statement. If Flint Creek were abandoned today, the loss would be more than $25 million. The loss will either result in a decrease in AECC's member cooperative's equity or will have to be recovered in future increased rates" (Highley Direct at 5).[4]

Mr. Highley does not mention that AECC's member equity was $512 million in October 2012, and has been growing over the years (from $495 million in October 2011, $460 in October 2010, and $434 million in 2009) (AECC 2012 Financial Statements at 3; 2010 Annual Report at 5. These documents attached as Exhibit PC-F2). If that trend continues, the write-off of Flint Creek would slow, but not eliminate, the increase in equity in the year.

Q: What are your conclusions?

A: My most important conclusion is that SWEPCo is incorrect when it claims that rejection of the Flint Creek controls package would require the plant to be retired by April 2015. The EPA is highly unlikely to require the retirement of Flint Creek so long as it is needed for reliability and SWEPCo is working on replacement resources. Hence, all of SWEPCo's other projections of the effects of that retirement on reliability are irrelevant.

In addition, SWEPCo has overstated the following concerns:

- the time required for planning and building new transmission to serve northwest Arkansas.

[4] Depreciation on AECC's portion of Flint Creek is 3.1% of the gross investment of $108 million (Exhibit PC-F2, AECC 2012 Financial Statements at 8), or over $3 million annually, so much of the remaining investment would be depreciated by the time Flint Creek would be retired around 2017.

- the problems involved in purchasing existing generation resources and obtaining transmission rights between those resources and the AEP region,
- the problems that would arise if northwest Arkansas were to operate without Flint Creek (due to retirement or forced outage) prior to completion of a new transmission line.

In short, SWEPCo has not demonstrated that retiring Flint Creek and replacing it with existing combined-cycle capacity and (if necessary) new transmission into northwest Arkansas is not feasible.

Q: What exhibits do you attach to this testimony?

A: I have attached eight exhibits, which provide the following information:

- the EPA's position on extending MATS compliance deadlines for generators essential to reliability.
- the FERC's position on reviewing reliability in support of the EPA's determinations of need.
- an email from SPP that provided informal responses to certain of Sierra Club's formal discovery.
- financial data from AECC.
- a Louisiana PSC Staff Report on the operation of the Market-Based Mechanism.
- excerpts from the SPP's 2012 For EIA-411.
- transmission-planning reliability criteria for AEP-SPP.
- for the Commission's convenience, copies of the non-confidential discovery responses I cite.

II. Deadlines for the Shutdown of Flint Creek

Q: What is SWEPCo's position regarding the deadline for the shutdown of the Flint Creek coal plant if it does not install equipment to meet MATS?

A: The nominal deadline for compliance with MATS is April 16, 2015, as pointed out by Ms. McCellon-Allen (Direct at 10) and Ms. Bennett (Sur-Surrebuttal at 8). In her January 2013 direct testimony, Ms. McCellon-Allen portrays the April 2015 date as a drop-dead date, after which Flint Creek could no longer be operated, and by which time all replacement resources must be procured:

> the Flint Creek plant must be retrofitted to dramatically reduce emissions or it will have to be retired by April 2015. (McCellon-Allen Direct at 30)

> [replacement resources must] be implemented as soon as possible after the April, 2015 date when Flint Creek will no longer be available to serve customers. (McCellon-Allen Direct at 10)

> obtaining additional capacity from [merchant] generating resources by 2015 presents considerable challenges. (McCellon-Allen Direct at 19)

> Flint Creek would no longer be available for dispatch past April, 2015…. (McCellon-Allen Direct 20)

Q: Is April 2015 the actual drop-dead date for shutdown of Flint Creek if it is not retrofit to meet MATS?

A: No. Despite her repeated insistence that Flint Creek would no longer be available past April 2015, even Ms. McCellon-Allen admits that development of a compliance plan would give Flint Creek another year:

> If…there is no other plan for compliance with MATS that will allow the facility to avail itself of the 1-year compliance extension, Flint Creek will not be permitted under state or federal regulation to operate beyond April 2015. (McCellon-Allen Direct at 10, footnote 1)

A plan to retire Flint Creek would be that "other plan for compliance with MATS that will allow the facility to avail itself of the 1-year compliance extension." Indeed, AEP has experience with this deadline in association with retirement of units that are not being retrofitted for MATS compliance, since April 16, 2016 is the deadline for shutdown of the uncontrolled unit at PSO's Northeastern unit. Hence, Ms. McCellon-Allen's repeated assertions of a 2015 deadline amount to nothing more than an attempt to mislead and panic the Commission into approving SWEPCo's proposed retrofits, regardless of the existence of less-expensive alternatives.

In sur-surrebuttal testimony, SWEPCo was more candid. Ms. Bennett acknowledged that "with a mitigating solution in the works…[SWEPCo] could petition the State for an extra year to comply," referring to the one-year extension option available under Clean Air Act §112(i)(3)(B). This extra year makes the effective deadline 2016, not 2015 (Bennett Sur-surrebuttal at 8).

Q: So is April 2016 the actual date at which Flint Creek would be required to shut down?

A: No. The April 2016 deadline does not apply to units that are required for reliability. Exhibit PC-F3 is the EPA's memorandum on its enforcement response policy for MATS for plants that are required for electric reliability. Under the process described in that policy, a generator could continue to operate, without penalty, until at least April 2017, as needed to maintain reliability. As the EPA explains in that memorandum,

> Where there is a conflict between timely compliance with a particular requirement and electric reliability, the EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare. (Exhibit PC-F3 at 1)

> The EPA generally does not speak publicly to the intended scope of its enforcement efforts, particularly years in advance of the date when a violation may occur. The Agency is doing so now with respect to the MATS to provide confidence with respect to electric reliability. EGUs may be needed to operate to maintain the reliability of the electric grid when they would prefer, or could be required, to halt operations…indefinitely (through deactivation of a unit). This policy describes the EPA's intended enforcement response in such instances. The policy is informed, as are our enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response. (Exhibit PC-F3 at 4)

Specifically, the EPA states that it will issue an Administrative Order (AO) for a generator that requires another year to comply—until April 2017—due to reliability constraints:

> Some sources may take all steps necessary to comply with the MATS, but may nevertheless be needed to operate in noncompliance with the MATS to address concerns with electric reliability.… the EPA intends, where necessary to avoid a serious risk to electric reliability, and provided the criteria set forth herein are met, to issue an expeditious case-specific AO to bring a source into compliance within one year.… Any such AOs would be…limited to units that are required to run for reliability purposes that (A) would otherwise be deactivated, or (B) due to factors beyond the control of the owner/operator, have a delay in installation of controls or need to operate because another unit has had such a delay. (Exhibit PC-F3 at 4)

Q: Will EPA perform its own analysis of the reliability need for Flint Creek?

A: No. The EPA has explained that it will rely on other organizations:

> in light of the complexity of the electric system and the local nature of many reliability issues, the EPA will…rely for identification and/or analysis of reliability risks upon the advice and counsel of reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ('FERC'), Regional Transmission Operators ('RTOs'), Independent System Operators ('ISOs') and other Planning Authorities as identified herein, the North American Electric Reliability Corporation ('NERC') and affiliated regional entities, and state public service commissions (Exhibit PC-F3 at 2)

> the EPA intends to consult, as necessary or appropriate on a case-by-case basis, with FERC and/or other entities with relevant reliability expertise. (Exhibit PC-F3 at 7)

In order to demonstrate the need for an AO, Flint Creek would need to file the following items by October 2015 (Exhibit PC-F3 at 7):

> Written analysis of the reliability risk if the unit were not in operation, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with FERC,…or (b) cause reserves to fall below the required system reserve margin.
>
> Written concurrence with the analysis [above] by, or a separate and equivalent analysis by, the Planning Authority for the area in which the relevant EGU or EGUs are located,…and, where practicable, any related system wide analysis by such entity.
>
> …a written demonstration of the plan to resolve the underlying reliability problem and the steps and timeframe for implementing it, which demonstrates that such resolution cannot be effected on or before the MATS Compliance Date.
>
> An identification of the level of operation of the unit that is required to avoid the documented reliability risk…and, consistent with that level, a proposal for operational limits and/or work practices to minimize or mitigate any [hazardous air pollution] emissions to the extent practicable during any operation not in full compliance with the MATS.

Q: Would SWEPCo be able to make the showing needed to obtain an AO?

A: Probably. The Company would need to demonstrate the following:

- the existence of one or more problems that require continued operation of future costs of Flint Creek,
- concurrence of the regional planning authority,
- progress towards a solution to those problems to allow retirement, and
- the level of operation required to maintain reliability.

In its filings in this proceeding, SWEPCo has claimed that retirement of Flint Creek prior to the completion of new transmission would "result in the violation of at least one of the reliability criteria required to be filed with FERC" and "cause reserves to fall below the required system reserve margin." (See

Nickell Direct at 5, 8–9 for examples.) The remainder of the criteria to receive an AO would require additional documentation, including identification of the exact conditions under which Flint Creek would be required to operate. If the reliability or reserve-margin issues are real, SWEPCo should be able to document those problems over the next two-and-a-half years for the purposes of obtaining an AO from the EPA.

Q: Would SWEPCo have any difficulty obtaining the concurrence of the planning authority for northwest Arkansas?

A: No. The Southwest Power Pool is the Planning Authority for the SWEPCo transmission area, including northwest Arkansas. Mr. Nickell, SPP's Vice President of Engineering, has already supported SWEPCo's reliability claims and added his own concerns about meeting reserve standards.

The Southwest Power Pool is also the Regional Transmission Operator and the NERC-affiliated regional entity for the SWEPCo area, so it fills three of the organizational roles that EPA says it would turn to for advice.

Q: Would SWEPCo have any particular difficulty providing a plan to resolve the underlying reliability problem and allow retirement of Flint Creek?

A: I do not see why it would. Again, SWEPCo would have until October 2015 to show progress on licensing and siting the transmission line, to describe the remaining "steps and timeframe for implementing" the transmission solution, and to explain why "such resolution cannot be effected on or before" April 15, 2016. These tasks are all within SWEPCo's area of competence.

Q: What are the other organizations to which EPA would turn for advice on reliability issues?

A: The additional identified organizations are FERC, NERC and the Arkansas PSC.[5] The FERC has indicated that it would apply a very lax standard, examining "whether, based on the Commission's review of the informational filing, there *might* be a violation of a Commission-approved Reliability Standard" (FERC policy, attached as Exhibit PC-F4, at 8, 10, emphasis added), rather than whether a violation would be likely or inevitable.[6] The FERC also indicates it "may also identify issues within its jurisdiction other than a potential violation of a Commission-approved Reliability Standard." (Exhibit PC-F4, at . 10) It seems likely that FERC would support any plausible argument for the existence of a reliability problem.

This Commission would be free to form its own conclusions in 2015 and report them to the EPA.

Q: Has SWEPCo demonstrated in this proceeding that Flint Creek would be eligible for this further extension of the MATS compliance deadline?

A: As I will discuss in Section V, below, SWEPCo has provided incomplete descriptions of how Flint Creek's retirement would affect the potential reliability in northwest Arkansas. As a result, the current record might not be sufficient to support a request for an AO for Flint Creek. If SWEPCo is correct that operation of Flint Creek beyond April 2016 is necessary for reliability, SWEPCo will have over two years to document the situation to EPA's satisfaction. If SWEPCo cannot produce a coherent demonstration that

[5]It is possible that other state commissions would want to comment on reliability, reserve margins, and the timing constraints.

[6]The policy document is "Policy Statement on the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards" issued May 17, 2012, in Docket No. PL12-1-000.

retirement of Flint Creek prior to completion of new transmission would pose a serious reliability problem in northwest Arkansas, there probably is no such problem, in which case the PSC need not worry excessively about the retirement of Flint Creek in 2016.

Q: Assuming that SWEPCo can provide a coherent explanation of the need for Flint Creek until new transmission is constructed, produce a plan for building the transmission and demonstrate the support of SPP, what other conditions would SWEPCo need to justify an extension of Flint Creek's compliance deadline?

A: The last requirement laid out by the EPA (Exhibit PC-F3 at 7) is that SWEPCo would need to identify "the level of operation of the unit that is required to avoid the documented reliability risk" and associated operational limits. In this docket, SWEPCo assumed that Flint Creek would need to operate at its minimum load level (about 330 MW or 63% of full load) for the summer and winter months, or roughly a 35%–40% annual capacity factor (Weaver Rebuttal at 8; SWEPCo Responses to Sierra Club Data Request 1-165b and to APSC Data Request 5-4).[7] The Company assumed that these reliability constraints would be binding only if Flint Creek were converted to operate on gas.

On the other hand, the weekly data that SWEPCo provided on the loads in northwest Arkansas indicate that load has been within 330 MW of peak in only 14 to 19 weeks of the year (SWEPCo Response to Sierra Club Data Request 7-282). If 330 MW of Flint Creek output is sufficient to back up the existing transmission system at peak, no Flint Creek capacity should be required when

[7]For the Commission's convenience, I attach the non-confidential responses to data requests that I cite as Exhibit PC-F1. The two responses cited here are confidential and are not included in my exhibit.

loads are 330 MW below peak. Operating Flint Creek at 330 MW for 14–19 weeks would result in a capacity factor of 17%–23%. Since the high loads are less likely on weekends, and not every weekday in a high-load week would be expected to have a high load, Flint Creek could probably operate much less, even if SWEPCo's assumed need for 330 MW at peak is correct. An average of four days of operation in the high-load weeks would result in a capacity factor of 10%–13%.

The EPA would probably want to see an analysis of the load levels at which Flint Creek operation would be required, so that specific operational limits could be written into the AO, minimizing Flint Creek's emissions of mercury and other hazardous air pollutants, while providing SWEPCo with the operational flexibility necessary to maintain reliable service. Again, SWEPCo should be able to complete that analysis by October 2015.

Q: Is SWEPCo aware of these provisions for extending the MATS compliance date?

A: Yes. On discovery, SWEPCo summarizes those provisions as follows:

> U.S. EPA has stated that…it may be reasonable to grant the 1-year extension if the permitting authority determines, based on information from the regional transmission organization, that continued operation of a particular unit slated for retirement for some or all of the additional year is necessary because…transmission upgrades are needed in order to maintain electric reliability after the unit is retired. (SWEPCo Response to Sierra Club Data Request 7-244a)

> U.S. EPA has issued a policy memorandum,…which describes its intended enforcement policy with respect to sources that must operate in noncompliance with the MATS for up to a year to address a specific and documented reliability concerns. Under the enforcement policy, a source that qualifies for a one year extension from the permitting authority may also qualify for an additional year under an administrative order by U.S. EPA, provided that the unit is critical for reliability purposes and otherwise falls within the terms of the policy. (SWEPCo Response to Sierra Club Data Request 7-244b)

These responses demonstrate that SWEPCo is aware that Flint Creek would be available for dispatch for years past April 2015.

Q: Is April 2017 then the final drop-dead date for the shut-down of Flint Creek?

A: No. The EPA recognizes that longer delays may be necessary, as follows:

> This policy does not address situations where a reliability critical unit needs more than one year to come into compliance after the MATS Compliance Date....The EPA intends to handle such scenarios as it has in the past, by assessing each situation on a case-by-case basis, at the appropriate lime, to determine the appropriate enforcement response and resolution. (Exhibit PC-F3 at 2)

Q: Please summarize the time frame for SWEPCo to implement transmission and/or generation alternatives and shut down Flint Creek.

A: The EPA has indicated that it does not intend to force the shutdown of generators needed for reliability until reliability solutions can be implemented. Under the guidance provided to date, there is a clear path to continue operating Flint Creek until April 16, 2017, to the extent necessary to maintain reliable power supply in northwest Arkansas.[8] If the transmission and/or generation solutions to the reliability issues identified in northwest Arkansas cannot be fully implemented by April 2017, EPA has indicated that it will work out solutions on a case-by-case basis. While SWEPCo should be acting promptly to document the need for the delay and to prepare for construction of any necessary transmission and initiation of procurement of new resources, there is no reason to believe that the EPA will endanger reliability.

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[8]Since SWEPCo has indicated that Flint Creek is not needed for reliability , (SWEPCo HSPI response to Sierra Club Data Request 1-165b), June 2017 would be the effective deadline for the reliability solutions with an Administrative Order extending operation past the winter 2017 period.

III. Timeline for Replacement Generation

Q: What concerns does SWEPCo raise regarding the timeline for acquiring generation to replace Flint Creek?

A: While SWEPCo's original filing in this proceeding treated purchases of existing resources as impractical or irrelevant (Weaver Direct at 54–55), the January 2013 filing accepts a purchase as the most likely replacement, but raises concerns about delays due to the following three requirements:[9]

- The Market-Based Mechanism (MBM) required by the Louisiana PSC, which could delay the acquisition of replacement resources by one year (McCellon-Allen Direct at 21) or "a year or more" (9) or "approximately 7 to 12 months" (Bennett Rebuttal at 18).
- The SPP Transmission Service Study process which would require two years (McCellon-Allen Direct at 21) or "more than one year, and can take up to two years" (Nickell Direct at 9), or 12–18 months (Ross Rebuttal at 8).
- The need to "obtain the necessary firm transmission service from SPP" for the replacement capacity, which might take between two and three years (McCellon-Allen Direct at 20), exposing SWEPCo to "compliance risk" (Nickell Direct at 9–10).

[9]While Ms. McCellon-Allen in her January testimony claims that only three combined-cycle plants are known to have capacity for sale (Direct at 19), she later adds Green Country to this list (Direct at 20). She does not claim that no capacity is available from the other plants listed in Table 4 of my direct testimony, only that "We do not have information on what capacity is available from these plants" (SWEPCo Response to Sierra Club Data Request 7-250, which also lists additional six plants that have bid into AEP RFPs since 2008).

A. *The Louisiana Market-Based Mechanism*

Q: What is SWEPCo's projection for how long the MBM would delay the acquisition of generation resources?

A: Ms. McCellon-Allen suggests (Direct at 12) that the schedule should be based on the Company's experience and "When SWEPCo last implemented the LPSC's MBM approval process for major new generation resources, the process took 12 months to complete."

Q: Is this a relevant comparison?

A: No. Although the Sierra Club asked SWEPCo to provide details on past MBM applications filed by SWEPCo and other utilities (including dates of filing, RFP and decision, nature and date of need and the utility's proposed resources), SWEPCo provided only a list of four of its filings, by date. (SWEPCo Response to Sierra Club Data Request 7-242) SWEPCo should remain familiar with the LPSC's implementation of its MBM order, given that SWEPCo is concerned that the MBM would be a barrier to timely resource planning.

Ms. McCellon-Allen's 12-month estimate appears to be a reference to some part of SWEPCo's complex filings related to the following projects:

- building the Mattison peakers,
- building the Stall combined-cycle plant,
- building the Turk coal plant,
- making short-term purchases,
- entering into long-term purchased-power agreements.

Self-build proposals, especially simultaneous proposals for multiple facilities, would generally take longer to resolve than proposals for purchases. Thus, the 12-month period reported by Ms. McCellon-Allen is not a good predictor of the MBM process duration for a simpler purchase transaction.

Moreover, since that set of overlapping filings, the LPSC has shortened the amount of notice the utility must give the Commission before filing a draft RFP from 60 to 30 days.[10]

The Louisiana PSC has approved further modifications to the basic MBM process to accommodate utility circumstances, including waiving the requirement for Entergy to file a draft RFP in 2010, reducing notice and review periods for Entergy in June 2012, and waiving the entire process for the Dixieland co-op, which ran its own RFP process.[11] In 2008, the LPSC Staff reported, "To date, no request for an MBM exemption has been rejected in a Commission certification case" (LPSC Docket R-26172-C, October 7, 2008, Staff Report, attached as Exhibit PC-F5, at 24).

A relatively recent MBM process, concerning a mid-term purchase by CLECo, started with the filing of the Notice of Intent on August 8, 2011 and ended less than nine months later with a settlement filed March 21, 2012 (LPSC Docket No. U-32223). Much of that time was occupied by the RFP process that would have been necessary for any efficient and orderly power acquisition.

Thus the evidence shows that the delay introduced by the MBM process is likely to be closer to the low end of the seven-to-twelve-month range given by Ms. Bennett (Sur-Surrebuttal at 20) than to the 12-month estimate preferred by Ms. McCellon-Allen.

Q: Could the MBM requirements preclude SWEPCo from purchasing resources to fill any short-term capacity deficiency?

[10]LPSC Docket R-26172, subdocket C, October 15, 2008 General Order, Appendix C ¶2.

[11]Louisiana PSC Special Order No. 34-2010 (7/28/2010); Louisiana PSC Minutes from June 28, 2012 Open Session; Louisiana PSC Order No. U-32275 (Corrected) 11/15/12.

A: No. The MBM does not apply to a contract for less than three years with non-affiliates.

B. Firm Transmission Service

Q: What do the SWEPCo witnesses say about the process of procuring transmission service for newly purchased generation entitlements?

A: They testify that there would likely be multi-year delays in obtaining firm transmission service:

> However, the timing for the transmission upgrades required is a critical issue. Typically, transmission upgrades require two to three years to complete after a transmission service study, which may also take one to two years to complete. This timeframe does not match the need, as Flint Creek would no longer be available for dispatch past April, 2015, and reliability risks would exist until upgrades were completed. (McCellon-Allen Direct at 20)

> SPP's transmission service administration process…usually takes more than one year, and can take up to two years, from the time transmission service request is submitted to obtain a transmission service agreement for the requested service….is likely that transmission upgrades would have to be constructed as a condition to receiving the service which could add an additional 3-5 years before delivery of the capacity is actually achievable. (Nickell Direct at 9–10)

Mr. Nickell also warns that the reduction in AEP's reserve margin due to a delay in procuring transmission rights for purchases to replace Flint Creek

> puts SWEPCo in an untenable situation of not only incurring risks of non-compliance with SPP Criteria, but also introducing unacceptable reliability risk to the region. (Direct at 9)

He then states that "SWEPCo and the region would be subject to unavoidable compliance and reliability risks" (Direct at 10).

Q: Their descriptions of the problem with obtaining firm transmission service certainly sound dire. Would SPP refuse to dispatch generation to serve

SWEPCo or northwest Arkansas if the firm transmission rights from resource purchases were not yet secure?

A: No. Even if SWEPCo does not hold all the transmission rights that would be required under the SPP process, SPP will continue to serve SWEPCo load (SWEPCo Response to Sierra Club Data Request 7-252).[12] Lack of contractual transmission paths should not be a reliability problem for the AEP sub-region, especially since the AEP sub-region has 2,169 MW of capacity with firm supply contracts outside the region. (SWEPCo Response to Sierra Club Data Request 7-279) Regardless of what happens on a contractual basis, the energy generated in AEP's sub-region is available to support load in the region, while generation owned by SWEPCo outside the AEP sub-region serves loads near those generators. The electrons do not know who has purchased them.

Q: What are the "risks of non-compliance" that concern Mr. Nickell?

A: Mr. Nickell was unable to identify any specific penalties for non-compliance related to the delay in obtaining transmission rights. He says that "SPP has not directly issued penalties for non-compliance with SPP Criteria primarily because SPP members take their responsibilities seriously and strive diligently to meet those requirements" (SWEPCo Response to Sierra Club Data Request 7-280). The reserve margin target is an SPP requirement (Nickell Direct at 8–9), so SPP would be the obvious entity to assess any penalties. Nor does Mr. Nickell offer any evidence that SWEPCo is not striving diligently to meet its share of AEP's capacity requirement, or would not strive diligently to do so

[12]The only situation SWEPCo has identified in which that would not be possible were if Flint Creek were retired and the multiple transmission outages I describe in Section V.A occurred before the Fort Smith–Chambers Spring transmission line were complete. As I explain in Section II, Flint Creek will almost certainly continue operating until the new transmission line is built.

following an economic decision to retire Flint Creek. While he suggests that NERC or FERC could assess penalties for having a low reserve margin, he does not provide any evidence of either entity doing so, especially while the affected utility is attempting to procure transmission rights.

Q: What are the unacceptable reliability risks of which Mr. Nickell warns (Direct at 9)?

A: It is not clear whether he is warning about the reserve levels in SPP as a whole or in the AEP sub-region. As for the SPP region, the 2012 SPP Form EIA-411 (at 73, excerpts attached as Exhibit PC-F6) reports capacity margins of over 20% (equivalent to reserve margins over 27%) through 2022. That is a supply cushion of nearly 7,000 MW over the target 12% capacity margin (13.6% reserve margin), not counting some 4,400 MW of "other" capacity, which includes "Mothballed generation (that may be returned to service during peak demand)" and generation that is curtailable or non-firm, regardless of the probability of its availability when needed (Exhibit PC-F6 at 71).[13] The retirement of Flint Creek would have little effect on SPP's capacity surplus.

For the AEP sub-region, Mr. Nickell reports (Direct at 8) that "it was determined that capacity margin…would decrease from 11.8% to 9.6% following the retirement of Flint Creek." That would still be more than the 9.1% capacity margin SPP reports for the AEP sub-region in 2014 (2012 SPP Form EIA-411, p. 77); SWEPCo has not indicated that it has any urgent need for new resources in 2014. Short-term deviations from sub-region target reserve margins do not appear to pose any serious reliability problems.

[13]For example, a generator may not have firm transmission access when local load is low and generation is high, but it would not be needed for reliability at those times.

In addition, there are 2,169 MW of capacity in the AEP sub-region with contracts to deliver power outside that region (SWEPCo Response to Sierra Club Data Request 7-279), and extensive transmission interconnection between the AEP sub-region and other SPP sub-regions, and between AEP and Entergy, so there should be sufficient capacity available to serve loads in the AEP sub-region.

IV. Timeline for Constructing Transmission to Northwest Arkansas

Q: What is SWEPCo's position regarding the time that would be required to construct additional transmission into northwest Arkansas?

A: Mr. Nickell notes,

> a new 345 kV transmission facility would likely be a candidate solution to resolve the issues [he identifies]. However, Flint Creek's retirement would need to be evaluated in further detail within the SPP ITP process to confirm this assumption and select the most cost effective project for construction. (Nickell Direct at 10)

He goes on to suggest that "the study could take 1-3 years depending on the ITP process used," which might be the annual ITP Near-Term Assessment or the triennial ITP 10-Year Assessment.

Mr. Nickell estimates an additional four years for construction (Direct at 13).

Q: Would SPP's review of the proposed 345 kV transmission line from Fort Smith to Chamber Springs have to start from scratch?

A: No. The SPP has already reviewed the line and SPP staff recommended the adoption of a plan that included the Fort Smith–Chamber Springs line. The SPP

> has identified the proposed Fort Smith to Chamber Springs 345 kV transmission line as a robust, long-term solution that addresses the delivery of power to NW-AR as recognized in its 2010 ITP 20-year recommendation. When the plan was received at the SPP Board on January 25, 2011, the line was removed from the plan in the course of the meeting, since it was not needed for the ten year forecast and would impose added cost to SPP rate payers. (Hassink Rebuttal at 5)

Q: Is there any reason to believe that SWEPCo would need to seek SPP approval through the triennial long-term review process?

A: No. Since SWEPCo expects to need the new line once Flint Creek retires, the need would fall within the six-year horizon of the annual Near-Term Assessment. Mr. Nickell acknowledges,

> The ITP Near-Term Assessment could be used to identify a reliability need and an associated transmission expansion project to serve as the solution as long as the proper assumptions were contained in the evaluation at the time of the assessment. In that case, there would be no need to delay evaluation until the next ITP 10-Year Assessment. (SWEPCo Response to Sierra Club Data Request 7-287)

Q: Does Mr. Nickell provide any support for his estimate of four years for construction of the new line?

A: No. To the contrary, he describes a more complex project that was completed more quickly, one that

> consisted of about 90 miles of new 230 kV transmission line and associated substations with the construction work shared by three utilities" in the Acadiana Load Pocket "took approximately three years….Very little construction work on this project could be performed during summer months and other times of expected high consumer demand. Even during times of milder conditions during construction of this project, customers were put on energy conservation notices and load shedding plans were developed and ready to be utilized by the parties. (Nickell Direct at 11–12)

In contrast, the Fort Smith–Chamber Springs Line would be about 70 miles, and as described by Mr. Hassink (Direct at 8–9) would not involve construction of new substations or sharing of construction work among multiple utilities.

Mr. Nickell suggests that problems similar to those in Acadiana would arise for the Fort Smith–Chamber Springs line.

> Implementation of new transmission upgrades in the load pocket can also be challenging because of reliability risks imposed to the area during construction and connection of new facilities. For example, if a transmission project required that an outage of one of the existing primary sources of power for the area be taken in order to connect a new facility to the grid, SPP's Reliability Coordinator would be challenged to find a reliable way to facilitate the event without having to direct interruption of customers in the area. (Nickell Direct at 11)

Q: Is the new transmission line into northwest Arkansas likely to be significantly delayed by the construction limits imposed on the Acadiana project?

A: No, for three reasons. First, because the Fort Smith–Chamber Springs Line would require only two connections, one at each substation, the need to shut down facilities during interconnection would be limited. The vast majority of the construction work could be performed regardless of load level.

Second, the load data provided by SWEPCo show that in each of the last seven years, northwest Arkansas loads have been below 1,000 MW for 38 weeks, consistently below 900 MW for 29 weeks, and below 800 MW for 14 weeks (SWEPCo Response to Sierra Club Data Request 7-282). So there are considerable low-load periods in which interconnection work can be scheduled. Mr. Nickell indicates that

> Normally, multiple outages would need to occur over an extended period in order for work to be completed so that the new transmission line can be energized. Based on review of historical information over a two-year period, an average of 8 weeks of cumulative outage time would need to occur to tie in a new transmission line. (SWEPCo Response to Sierra Club Data Request 7-283)

Spreading those eight weeks over the 28 low-load weeks of 2016 and 2017 (the weeks that were historically consistently under 800 MW, or about 67% of peak), for example, would not appear to be very challenging.

Third, as discussed in Section II above, EPA has indicated that it will not require the shutdown of generators vital to reliability during the period in which replacement facilities are under construction. Flint Creek is almost certain to remain in operation, at least as needed for reliability, until after the new line is constructed.

Q: Given the information provided by SWEPCo, how long should it take to bring a new transmission line into service for northwest Arkansas?

A: Assuming one year for the SPP review, simultaneous review by the Arkansas PSC, and three years for construction, the line would be in service in 2017. Considering SWEPCo's obvious concern that the PSC will not pre-approve the retrofitting of Flint Creek, and SWEPCo's announced intention to retire the plant if it does not receive that approval, it would be prudent for SWEPCo to move forward with the SPP process and the initial design and routing of the line.

V. Operating Without Flint Creek and Major Replacements

A. Transmission Issues

Q: Does Mr. Nickell's testimony adequately support the conclusion that retirement of Flint Creek would result in serious reliability problems?

A: No, for the following reasons.

- His testimony is very vague and conclusory, omitting most of the details about the assumptions underlying his analysis.

- While he refers to "preemptive load shedding" due to the loss of a 345 kV line (Nickell Direct at 17), he provides no analysis demonstrating the conditions under which such load shedding would be required, nor does he demonstrate that activating a special protection system following a first contingency would not be sufficient.[14]
- Rather than answering Sierra Club's questions about the inputs to his analysis, Mr. Nickell provided 91 files that had unusual extension names, which turned out to be text files. Without a guide to the files and their meaning, it is difficult to understand what Mr. Nickell thought he found (SWEPCo Response to Sierra Club Data Request 2-272).[15]
- The load assumptions that Mr. Nickell used were overstated by anywhere from about 7% to 140% in the various model runs.
- The generation dispatch in the model runs does not appear to reflect the way that operators would actually dispatch generation to minimize outage risks for the modeled load and transmission conditions.
- The analysis does not appear to reflect realistic installation and operation of reactive power control and other transmission protection options.

Q: Please describe in more detail the documentation that Mr. Nickell provided.

A: In response to several of Sierra Club's data requests inquiring about specific inputs, assumptions, and results of the model runs, SWEPCo provided Attachment 7-272, which consisted of nearly 100 undocumented files with such

[14]Mr. Nickell also mentions a combined total of 47 days during which there was some period of outage on one of the two critical 345 kV lines that were experienced during 2012 (Direct at 17). He does not provide any information on how many of those outages were scheduled at low-load times for maintenance, nor whether any occurred at loads near peak.

[15]Mr. Nickell also provided a very large file in a specialized format that can only be read by transmission-modeling software.

impenetrable names as "Flint_Creek_2_branches_12.pvt" and "Flint_Creek_2_branches-ovl_6.rpt." In those files, the names of substations and power plants are abbreviated in ways that make them difficult to match with other sources. We received some clarification in an email from SPP counsel on February 25, nearly four weeks after the responses were due. That email is attached as Confidential Exhibit PC-F7.[16]

Mr. Nickell also refused to provide a map of the transmission lines and generators referenced in his model, instead referring to an incomplete map provided by SWEPCO in an earlier phase of discovery (SWEPCo Response to Sierra Club Data Request 7-256). While SWEPCo staff members tried to help me decode Mr. Nickell's abbreviations and locate the substations (in a February 14, 2013, conference call), they were not able to identify them all.

Q: Please explain why you say that the loads used in Mr. Nickell's analysis are overstated.

A: The lowest northwest-Arkansas load that Mr. Nickell modeled was 1,345 MW, and his other model runs used loads up to 3,045 MW. Mr. Nickell appears to have modeled 100 MW increments of load, as well as 20 MW increments from 1,645 MW to 1,725 MW. (SWEPCo Response to Sierra Club Data Request 7-272 Attachments and Exhibit PC-F7).

While Mr. Nickell claims that "The model utilized for this analysis reflects 2014 summer peak conditions" (Nickell Direct at 5), even the lowest load he modeled is rather high for a 2014 load, and the other load levels are entirely implausible. Mr. Nickell provides weekly peak load for each week of 2006–

[16]While that email did not indicate that its contents are confidential, I have marked Exhibit PC-F7 as confidential, since I cannot determine whether SWEPCo considers some of the information in the email to be confidential.

2011 (SWEPCo Response to Sierra Club Data Request 7-282, Attachment 1). Table 1 shows the maximum value for each year. Figure 1 compares the historical loads to the values that Mr. Nickell used.

Table 1: Northwest Arkansas Peak Loads

Year	Maximum Load
2006	1,152 MW
2007	1,190 MW
2008	1,219 MW
2009	1,117 MW
2010	1,207 MW
2011	1,276 MW
2012	1,233 MW

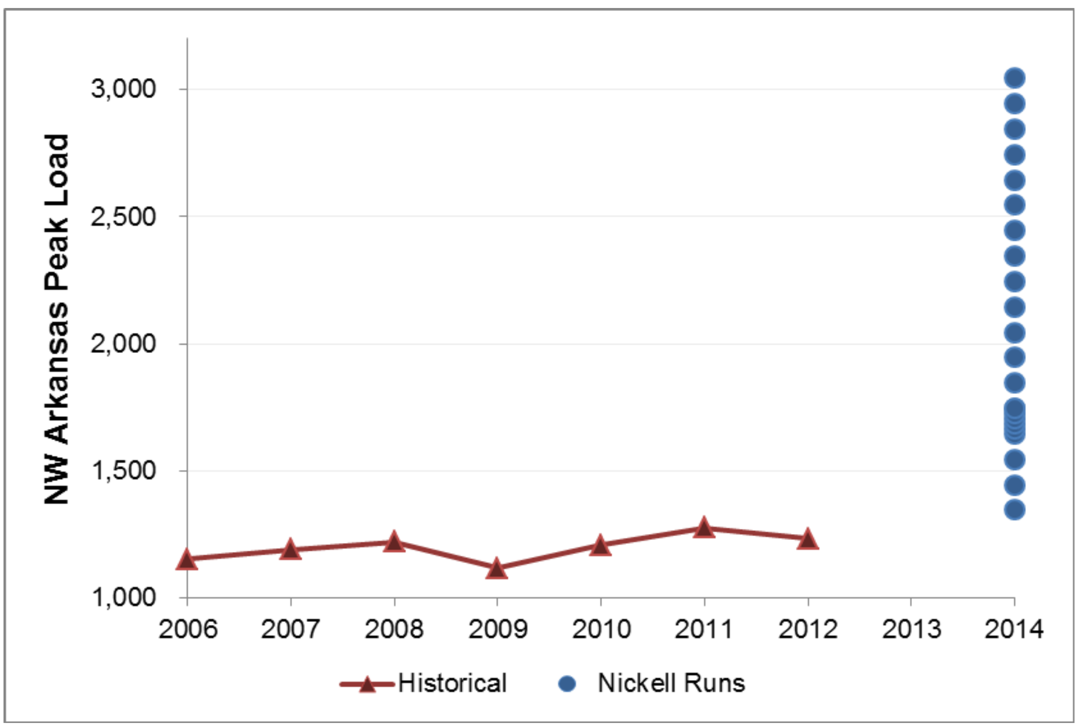

Figure 1: Northwest Arkansas Load, Historical and as Modeled by Mr. Nickell

The high load in 2011 was associated with an extremely hot summer. Even during the recovery from the recession, from 2010 to 2012, northwest Arkansas load grew only about 13 MW annually, or about 1%. At that rate, the northwest-Arkansas peak would not reach 1,345 MW until about 2020, by which time any necessary additional transmission facilities could be in service. In addition, the PSC's energy-efficiency proposed targets would require SWEPCo to reduce its Arkansas load by 1% in 2013, rising to 1.5% annually by 2015, greater than the recent historical load growth.[17]

Q: What is the implication of Mr. Nickell's choice of load levels?

A: His results are not useful to the Commission in determining what would happen were Flint Creek retired a year or two before the construction of another transmission line. Mr. Nickell claims,

> The results of this analysis indicate that once Flint Creek is removed from service, severe thermal overloads and voltage decreases occur due to transfers into the load area. These thermal overloads and voltage reductions increase the threat of cascading transmission outages within the area that would result in voltage collapse and customer power outages. (Nickell Direct at 5)

> The analysis showed that the absence of Flint Creek generation causes more flows into the area that result in voltage and thermal violations during contingency conditions. These violations were present in the analysis even before simulating power transfers into the area to meet increased consumer demand beyond that which was modeled. (SWEPCo Response to Sierra Club Data Request 7-271)[18]

In fact, his analyses do not show this mass of violations—voltage collapse, low-voltage, and thermal overloads—at the 1,345 MW load level. The most dire outcome, voltage collapse, occurs only for northwest-Arkansas loads at

[17]The recent historical data also includes some effects of energy-efficiency programs. Assuming that the summer peak for each year reflects half the effect of efficiency measures installed in that year (plus all previous installations), and that SWEPCo achieved the PSC targets in northwest Arkansas, the cumulative energy-efficiency effect would be about 0.1% in 2010 (about 1 MW) and 1.1% in 2012 (about 13 MW).

[18]The "power transfers into the area" are the 100 MW to 1,700 MW that Mr. Nickell adds to the already-high 1,345 MW he asserts was the forecast for 2014.

MW and above (Exhibit PC-F7). This is approximately higher than the highest previous northwest-Arkansas load.

Nor do voltage reductions appear to be a problem. The Transmission Planning Reliability Criteria for the AEP-SPP system specify the voltage limits as follows:

> Transmission voltage should not…fall below 90% of nominal voltage shown above during emergencies. The low limit can be lower if voltage regulating equipment maintains voltage to the customers within prescribed limits at distribution substations involved without causing voltage problems at nearby loads. (2012 American Electric Power AEP-SPP FERC Form 715 Part 4, excerpt attached as Exhibit PC-F8, at 4.3).

As for the voltage reductions, the lowest load at which any bus voltage fell below 90% of normal under any of the 27 contingencies that Mr. Nickell modeled was MW, vastly higher than any load likely in this decade.

Finally, Mr. Nickell's analysis shows that, under certain dispatch conditions, one line ( ) experiences overloads at MW.[19] This occurs under second contingency conditions, with the concurrent loss at peak of both the largest 345-kV line from the west into northwest Arkansas (Tonnece to Flint Creek) and either the second-largest 345-kV line (Clarksville to Chamber Springs) or the very short line from the to the adjacent substation.[20] Mr. Nickell also finds a rather small overload for a low-capacity line (a line from

[19]This line appears to be only about miles long, so reconductoring or reinforcing it may be relatively inexpensive and quick.

[20]The SWEPCo FERC Form 1 lists this line as 0.23 miles in length. From Google maps, it appears that the line spans only four poles.

) if the lines from GRDA 1 to Tonnece and from Clarksville to Chamber Springs fail.[21]

Q: What is wrong with the generation dispatch in the model runs?

A: I believe that there are three problems. First, "prior to any simulated power transfer and load increase…The conditions assumed are those in the SPP base model" (Erin Cullum e-mail, Exhibit PC-F7). Since the SPP base case includes the operation of Flint Creek, the dispatch of generation in that case would not reflect the post–Flint Creek transmission issues in northwest Arkansas. Specifically, when Flint Creek is operating, power tends to flow into northwest Arkansas from the west and out of northwest Arkansas to the northeast and east. With the retirement of Flint Creek (or even during outages at Flint Creek), SPP would dispatch more generation to the northeast and east to reduce the stress on the lines into northwest Arkansas from the west. There is no indication that Mr. Nickell modified dispatch to accommodate the retirement of Flint Creek.

Second, when Mr. Nickell increases load in northwest Arkansas, he says that he increases generation levels from

> Entergy Services, CLECo Power, Oklahoma Gas and Electric Company, American Electric Power West…, The Empire District Electric Company, and City Utilities of Springfield." (SWEPCo Response to Sierra Club Data Request 7-277)

That would include resources on all sides of northwest Arkansas. But the tables of generation for various load levels include only part of the region Mr. Nickell lists. Specifically, the generation that adapts to northwest Arkansas load includes plants in Oklahoma, SWEPCo's territory, Louisiana, and even some in Mississippi, but not Empire District generation to the northwest or Entergy

[21] This line runs to a substation called "," which is not on the map in SWEPCo Response to Sierra Club Data Request 1-184, or any other map I have been able to find.

Arkansas generation to the east. Again, Mr. Nickell's modeling appears to increase flows from the west, exacerbating the transmission problems in northwest Arkansas.

Third, Mr. Nickell does not appear to recognize that SPP would change dispatch in response to the first transmission contingency, before the second contingency would plausibly occur. The contingencies identified as possible problems in Mr. Nickell's analysis are rare and independent events. While a second line may fail before the first line is back in operation, the simultaneous outage of both lines is vanishingly unlikely.[22] In 15 to 30 minutes, SPP would be able to ramp up operating generation and call on fast-start peakers to the east, and ramp down generation to the west. Mr. Nickell's modeling does not appear reflect any such response to the first contingency. Indeed the files in SWEPCo Response to Sierra Club Data Request 272 with the extension ".prg" show that the program was instructed to "never" "adjust area interchanges," either before contingencies or afterward.

Q: Other than redispatching generation, do system operators have other options for redistributing load on transmission lines at high loads or following contingencies?

A: Yes. Transmission systems have various combinations of control devices to influence the flow of real and reactive power, to reduce line losses and avoid overloads. Those options include load-tap transformers, phase-shifters, and capacitors. Operators also arm Special Protection Systems when the system is under stress, to limit the effect of an outage of particular system elements.

[22]Extreme weather events (storms, tornadoes and the like) can knock out multiple transmission lines in short order, but those events also tend to knock out large parts of the distribution system, reducing load.

Q: Did Mr. Nickell's model runs use these options to maintain the reliability of the northwest-Arkansas system?

A: No. Table 2 shows the settings Mr. Nickell applied in his model, from the prg files in SWEPCo Response to Sierra Club Data Request 272. Mr. Nickell allowed the operation of phase-shifters to control real power flow, but turned off all other control equipment.

Table 2: Settings for Transmission Equipment in Nickell Model

Control Technique	Program Setting
Adjust ULTCS for MVAr flow control	Never
Adjust phase-shifters for MW flow control	In Pre-Contingency
Adjust static tap-changers for voltage control	Never
Adjust static tap-changers for MVar control	Never
Adjust static phase-shifters for MW control	Never
Adjust static series compensators	Never
Adjust automatic Special Protection System	Never
Adjust manual Special Protection System	Never

Q: Does Mr. Nickell include the capacitors and static compensator that Mr. Hassink says SWEPCo would add if Flint Creek were retired (Hassink Direct at 8)?

A: There is no indication that Mr. Nickell added those devices to his model of the SPP base case (which would not include the devices). The issues in siting these devices at existing substations and installing them should be much simpler than those related to the transmission line; getting them into service by 2017 should not be particularly challenging.

Q: Did SPP or SWEPCo develop a Special Protection System for northwest Arkansas during past outages at Flint Creek?

A: Apparently not. In response to a request for any such protection plans, Mr. Nickell said:

> Special plans or actions are identified and developed closer to real-time (anywhere from day ahead to days ahead of the expected outage) to address reliability studies that identify this resource as having an impact on any planned transmission outage in the area. The operating guides would include the constraint issue as identified, the appropriate congestion management action required and the entities that are responsible for taking the required action. (SWEPCo Response to Sierra Club Data Request 7-278)

It would seem that had SPP and SWEPCo been worried enough about the possibility of a summer outage at Flint Creek they would have prepared a response plan. They will have several years prior to the retirement of Flint Creek to prepare a Special Protection System for northwest Arkansas, covering "appropriate congestion management actions."

Q: Is there reason to believe that the transmission system in northwest Arkansas would survive the loss of two lines at a 1,345 MW load, after appropriately balancing load among transmission lines, changing generation dispatch before and after the first contingency, and utilizing protective equipment and systems?

A: Yes. Table 3 lists the summer contingency capacity of the northwest Arkansas interfaces, from SWEPCo Response to Sierra Club Data Request 7-258. Even taking out the two largest lines (from Tonnece and Clarksville), the sum of the remaining capacities is 2,360 MW, 75% higher than the 1,345 MW load Mr. Nickell assumed. The sum of the lines' capacities is 1,983 MW, twice the 968 MW net flow into northwest Arkansas (1,345 MW load minus 377 MW of generation). Flows on the lines could be within the contingency limits, even with imperfect balancing of the flows.

Table 3: Transmission and Generation Serving Northwest Arkansas

Supply into NW Arkansas	Voltage	Summer Contingency Capacity
Tonnece-Flint Creek	345 kV	1,367 MW
Monett-Flint Creek	345 kV	1,130 MW
Clarksville-Chamber Springs	345 kV	1,176 MW
Siloam Springs City (GRDA)–Siloam Springs	161 kV	317 MW
Decatur-Flint Creek	161 kV	268 MW
VBI-VBI North	69 kV	48 MW
Beaver Dam-Avoca REC	161 kV	220 MW
Mattison generation		300 MW
Elkins generation		60 MW
Ellis generation		17 MW

Q: Does Mr. Nickell raise any other concerns about operating the northwest-Arkansas system without Flint Creek, before the completion of new transmission?

A: Yes. Mr. Nickell expresses the concern that locational marginal prices (LMPs) in northwest Arkansas would rise in this period. (Nickell Direct at 14–16)

Q: Should this be a matter of significant concern to the Commission?

A: No. The higher prices paid in northwest Arkansas would be paid to the generators in northwest Arkansas: primarily SWEPCo's Mattison and to a lesser extent AECC's Ellis and the small Elkins hydropower plant. Hence, the vast majority of any additional energy charges will flow back to Arkansas utilities and their ratepayers.

B. Short-term Local Alternatives

Q: Are there additional local resources that could be deployed in northwest Arkansas to improve reliability?

A: Yes. Those options would include

- targeted energy-efficiency programs, using higher incentives, increased local marketing, and direct installation to accelerate participation in retrofit programs in northwest Arkansas;
- increases in load management programs, which can include dimming of lighting and resetting of thermostats in commercial building at times of peak demand;
- increases in interruptible contracts;
- enrollment of emergency generation as a demand-response measure to reduce load under extreme loads and contingency conditions; and
- encouraging installation of combined heat and power (CHP) for customers with water-heating and other thermal loads.

Q: Does this conclude your testimony?

A: Yes.

CERTIFICATE OF SERVICE

I, Derek Nelson, do hereby certify that on the 14th of March, 2013, a true and correct copy of the foregoing Sierra Club's public Second Supplemental Rebuttal Testimony and Exhibits of Paul Chernick were electronically filed with the Arkansas Public Service Commission, and electronically served by EFS upon all parties on the service list for this docket. Confidential versions of these documents are being filed with the Commission and will served upon all parties by next-day mail.

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