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EXECUTIVE SUMMARY

The report summarizes the findings and recommendations of the Working Group assembled pursuant to Arizona Corporation Commission Decision #61969, wherein a Process Standardization Working Group shall be formed, which shall consist of Arizona Corporation Commission staff, market participants, and the Residential Utility Consumer Office, and shall be coordinated by the Director, Utilities Division or the Director's designee. (ACC Decision #61969, p. 6 II. 21-24). Furthermore the scope of work was to review, evaluate, and provide written recommendations for standardizing transactions including, but not limited to, Electronic Data Interchange (EDI) transactions Meter Information (650), Consolidated Billing (810), Settlement with Scheduling Coordinators (810), Direct Access Service Request (814), Remittance Advice to Bank (820), Transaction Error (824), and Meter Reads (867).

The Process Standardization Working Group (PSWG) identified issues for consideration and grouped them into the following categories: Policy, Billing, Metering, Direct Access Service Request (DASR), and Remittance and Transaction Error reporting. Five subcommittees were formed to analyze business practices relating to their specific area and to submit implementation guides along with handbooks to the full Working Group.

The conclusion was reached early on in the process that the scope of the work to be accomplished by June 15 was greater than anticipated. Two of the subgroups, DASR and Remittance, were postponed to concentrate efforts on the other three subgroups. These subgroups will be convened sometime in early fall of 2000. The remaining groups have been working on reaching consensus for forming best practices and identifying issues that need to be looked at for a viable market in Arizona.

The PSWG received several compliments on how well all of the participants are working together. This, in part, is due to the facilitators, which were provided by the City of Mesa. Additionally, the PSWG participants have realized the need for standardization of processes. Although the weekly meetings have been very productive, the PSWG members believe there is a need for an ongoing process to continue the work.

The highlights of the Policy, Metering and Billing Subcommittees are contained in this report summary, as well as a summary perspective of

Arizona's Electric Cooperatives. Lastly, a brief summary of the current status of Direct Access in Arizona is included.

POLICY SUBCOMMITTEE

The Policy group was formed to look at over-arching issues, and concerns that the market participants presented. Some of the concerns were due to the different implementation of Direct Access (DA) processes by the Utility Distribution Companies (UDCs). Others involved rules that have been found to be unworkable or that created barriers to the market.

The market participants identified twenty-four issues that the policy group has been discussing.

Accomplishments:
The group came to consensus on seven of these issues to date with the following recommendations.

- EDI should be the format used to electronically transfer data. There are not any available versions of XML in use at the present time. Market participants are using EDI, and formats needed for Direct Access have been created by the Utility Industry Group (UIG) and others. Arizona should keep in touch with the national market movement to be prepared to make the switch to XML with the rest of the market.
- Need to define 'standardized workday' using a modified North American Reliability Council (NERC) holiday schedule. Most of the providers of retail service are not 7days a week operations. These include billing, metering, meter reading, and DASR services. All providers need to know when to expect the receipt of data without having to track individual participant calendars.
- Allow the UDCs to provide Meter Service Provider (MSP) and Meter Reading Service Provider (MRSP) services for commercial load profiled customers to give small commercial customers retail choice. It is not cost effective to send personnel out to read a few meters per read cycle. Allowing the UDC to provide MRSP and MSP services for profiled commercial customers will give small commercial customers retail choice.
- There is no need to standardize the rounding of billing and metering data because the PSWG found that these issues were not widespread and the magnitude is fairly small.
- It has been agreed that a formal communication method (similar to MADEN) will be utilized to formalize the process of reporting meter exceptions between UDCs and Electric Service Providers (ESPs). A process to communicate transaction errors is needed to prevent

customers from receiving incorrect bills. The process will be set up so that corrections will be made prior to customers receiving bills.

- Arizona should not implement the use of the Universal Meter Identifier (UMI). The cost to implement UMI for Arizona only is high with little or no benefit.
- All Arizona EDI transaction set data content will utilize Greenwich Mean Time (GMT) to standardize time for business transactions. A time standard would help market participants, particularly MRSPs, to save costs by not having to adapt their systems to Arizona's unique requirements. In addition, it may prevent costly errors during the settlement process.
- UDCs and ESPs should only include the line items for services they are providing on the bill to the end use customer.

The group recognizes that some of these issues will require ACC action such as rule change and/or waiver of the current rules. Others require the Utilities Division Director to make a change in an operating procedure. The following table shows which issues require ACC action:

Issue	ACC Rule	ACC Operating Procedure
Standardize Workdays	R14-2-1612 (K)(12)	
Commercial load profile	R14-2-1615 (B)(1)	
Universal Meter Identifier		MSP Procedure
GMT		MRSP Procedure

Remaining Work

- Ownership of Current Transformers (CTs) and Voltage Transformers (VTs) and related issues. The cost for a customer to switch is too expensive if they have to purchase the CTs and VTs. Where does the liability for accuracy lie if the UDC retains portions of the metering systems?
- Are 997s (EDI Functional Acknowledgement) required for all transactions? The amount of data flowing between providers is already excessive. How would an entity know that its data has been received if 997s were not sent?
- Non-availability of local alternatives for providing competitively priced metering services. At the present time, it is not cost effective for an MSP to have an Arizona presence, which will cost the customer.
- Clarification on when a UDC can be an MSP. ACC Rules Question: Can the UDC provide metering and installation services for non-residential DA customers? No, the UDC can not provide metering and installation services for non-residential DA customers but Cooperatives can in their own territory.

- UDCs and market participants need a clearly defined communication process for promptly communicating and resolving problems with data, meters, or bills among ESPs, MSPs, MRSPs, and the UDCs.
- Will the UDCs allow ESPs to interrogate meters on non-DA customers for load research purposes/ billing option purposes? Depending on the circumstances and the UDC.
- Standardization of Billing Options (ESP and UDC consolidated billing as well as dual billing) from all UDCs should be implemented immediately to provide customer choice.
- UDC fees for Direct Access services (Customer Information Service Request (CISR), DASR, metering, meter reading, billing, settlement, etc.) are too high and not consistent between UDCs.
- Who is responsible for tracking the performance of MSPs and MRSPs? What is the process for communicating this information?
- What is the enforceability of the recommended processes or rules of non-ACC jurisdictional entities?
- A utility can back-bill a 3rd party (if the 3rd party is at fault) up to 12 months (R14-2-210(E)(3). This is only specific to the utility. Should the rule be applicable to other participants other than just the utility?
- There is no language in the rules keeping the MSP from contracting directly with the customers, how should this issue be addressed? This has not been anticipated.

BILLING SUBCOMMITTEE

The Billing Subcommittee was formed to establish workable processes for billing transaction, which will be utilized by all market participants. The group was faced with significant challenges due to the following:

- Existing utility systems were not designed to work with external systems
- Direct Access requires new ways of operating with existing systems and business practices
- Direct Access requires significant resources (cost and time) to make system changes to serve the current market demand
- The Arizona Cooperatives and rural utilities have unique circumstances with respect to Direct Access due to size, location of territory, customer base, and resource constraints

The group identified and prioritized five Direct Access Billing Functions:

- Bill to End-Use Customer
- ESP Consolidated
- UDC Consolidated
- True Up and Settlement Statements
- True Up and Settlement Invoices

The group prioritized ESP Consolidated Billing as the first billing transaction to be addressed.

Identification of major/critical issues related to ESP Consolidated Billing was another step. Issues were defined as questions, concerns, and/or lack of clarity in protocols or Rules. Processes that had not been identified in the original protocols, Rules and procedures were also addressed. The issues were prioritized and worked accordingly. The resolved issues are located in Appendix B-A. The unresolved issues are listed in Appendix B-B.

Accomplishments:

- Standardization of several billing processes
- Avoidance of costly changes to systems for both the ESP and UDC with interim solutions
- Identification of items that were not originally covered
- Resolved 16 of 27 issues
- Resolved all "current" high priority issues pertaining to ESP Consolidated Billing
- Gained a common understanding of current operating processes
- Reached agreement on data elements for standardization of the EDI 810. The EDI 810 Transaction is an electronic exchange of data between the UDC and the ESP, which allows the ESP to produce a customer's bill with the UDC charges.
- Recommended several processes of standardization (outlined in greater detail within this report).

Remaining work

- Complete the unresolved issues relating to ESP Consolidated billing
- Recommend and finalize the 810 Transaction
- Begin working on UDC Consolidated, True Up and Settlement Statements, True Up and Settlement Invoices, and Bill to End Use Customer
- Continue to identify and conduct an in-depth analysis of Rules, allowing for flexibility of market systems and interim solutions for Direct Access billing.

The Billing subcommittee has made tremendous strides in accomplishing its goals and will continue to work to achieve the goals and objectives set forth in PSWG. The group still has a large amount of work to be completed and will continue to pursue the best billing processes for the Arizona market.

As of the date of this report, we are recommending the following business processes outlined in the Billing sections of the report, for standardization.

B 1. ESP Consolidated Billing
B 2. Interim Re-Bill Data
B 3. Billing Exception Notices (BEN)
B 4. EDI 810 Transaction

METERING SYSTEMS AND METER READING SUBCOMMITTEE

The Metering Systems and Meter Reading Subcommittee was formed to establish workable processes for exchanging, installing, removing, and reading meters which would be utilized by all market participants. The subcommittee faced several challenges during the past few months in order to achieve consensus of suggested best metering processes for the Arizona market. They are as follows:

- Existing utility billing systems and processes are not designed to work with or interface with external meter reading systems in order to bill the electric service customer. Therefore, the parameters of reading and delivering meter read data need to be consistent for all billing entities.
- Existing UDC Metering Departmental processes are not designed to interface with external metering personnel or equipment.
- Direct Access requires the transmission of a significant amount of data related to metering equipment and systems.
- The Arizona Cooperatives have unique circumstances with respect to Direct Access due to size, location of territory, customer base, and resource constraints.

Realizing the magnitude of the subcommittee's charge, the group prioritized the metering transactions based on the likelihood and criticality of when they would occur in the Direct Access process. Therefore, the group focused their efforts on determining the best practice for the meter exchange processes for the initial switch to Direct Access services from Standard Offer services since it is the first transaction encountered by Market Participants. It was further determined that the meter reading processes would be re-evaluated at a future date due to a workable Arizona EDI 867, which was adopted in July 1999.

Standardizing this process required the group to look at not only the business processes, ACC Retail Electric Competition Rules, Electric Power Competition Act (House Bill 2663), and timing requirements that

many of the Utilities already have in place but also, proposals from Providers on how they would like to do business. The group also compared the common data elements and business processes with other industry standards; other market competition models, Coalition for Uniform Business Rules (CUBR), and Utility Industry Group (UIG).

The process identified in this report includes agreed upon data elements, business rules, meter data and scheduling forms, as well as transport mechanisms to be followed in association with each process. Additionally, all supporting documentation is included either in the report or in the Appendix to the report.

Accomplishments:

- Standardization of metering forms used to transmit data. Arizona Public Service (APS), Salt River Project (SRP), and Tucson Electric Power Company (TEP) have agreed to implement use of the forms beginning June 1, 2000. Citizens Utilities Company has agreed to implement use of these forms when Citizens' territory is opened to competition. The implementation of these forms by Arizona Electric Cooperatives is yet to be determined.
- Identification and standardization of several UDC timing requirements related to metering business processes. These standards will be utilized when developing additional metering processes.
- Identification and standardization of several UDC metering business processes needed to ensure the customer's smooth transition to Direct Access. These standards will also be utilized when developing additional metering processes.
- Identification and consensus of certain data elements that must be exchanged between Market Participants. These data elements will eventually be utilized in the construction and implementation of the EDI 650 transaction.
- Resolved 7 of 15 issues
- Gained a common understanding of current metering operating processes amongst the participants in the Arizona market.

Remaining work:

- Develop short term method for transmitting data electronically in a flexible format (i.e. CSV, Excel) for the Existing Meter Information (EMI), Meter & Data Communication Request (MDCR), and Meter Installation/Removal Notice (MIRN) forms
- Develop data element definition document (on-going for all processes)
- Develop Arizona Metering Handbook (on-going for all processes)

- Begin work on other Meter Processes: (Many of the timing requirements, data elements, and business rules have already been identified and are in various stages of implementation by the Market Participants.)
  - Customer returning to UDC Standard Offer from Direct Access
  - ESP to ESP switch requiring meter work
  - Disconnect requiring meter work
  - Seamless Direct Access customer moves
  - Routine meter test
  - Notification of meter maintenance
  - Cancel DASR with pending metering work
  - Update Active DASR requiring metering work
  - MSP/UDC meter work scheduling changes
  - Notification of electrical system change and permit request
  - Meter installation and approval process
  - Meter installation and energizing of electrical panel
  - Late MIRN notifications for DASR related work
- Develop EDI 650 Implementation Guide
- Begin looking at Meter Reading issues and processes
- Develop scenarios for exception reporting to be used for the Exception Reporting Subcommittee (MADEN)
- Determine distributed generation Direct Access metering processes

SUMMARY PERSPECTIVE OF ARIZONA'S ELECTIC COOPERATIVES

In Arizona, seven of the twelve Affected Utilities under the jurisdiction of the Arizona Corporation ("Commission") are rural electric cooperatives ("Cooperatives"). The Cooperatives include the Arizona Electric Power Cooperative, Inc. ("AEPCO"), Trico Electric Cooperative, Inc. ("Trico"), Duncan Valley Electric Cooperative, Inc. ("Duncan Valley"), Graham County Electric Cooperative, Inc. ("Graham County"), Mohave Electric Cooperative, Inc. ("Mohave"), Sulphur Springs Valley Electric Cooperative, Inc. ("Sulphur Springs"), and Navopache Electric Cooperative, Inc ("Navopache").

The Cooperatives provide a large block of electricity to consumers in Arizona. For example, the Cooperatives, together, serve over 135,000 consumers and provide over 800 MWs of load to the rural portions of the State. Specifically, Trico serves 24,899 meters, Duncan Valley serves 2,239 meters, Graham County serves 7,406 meters, Mohave serves 29,564 meters, Navopache serves 34,126 meters and Sulphur Springs serves 39,524 meters. AEPCO provides generation and transmission services to all of the Cooperatives, except Navopache. Navopache is currently served by Plains Electric and Transmission Cooperative from New Mexico. The rural nature of the Cooperatives' service areas must be emphasized. For example, the Cooperatives provide over 11,286 miles of line throughout Arizona. Thus, although the Cooperatives serve over 135,000 consumers in their respective service areas, this equates to less than 12 consumers per mile of distribution line.

The Cooperatives generally agree with the goal of the Process Standardization Working Group ("PSWG"), which is to establish a standardized process for the orderly implementation of full electric competition in Arizona. The concern is that the current work group activities will be construed to be a quasi-rulemaking process. The Cooperatives believe that a standardized process is appropriate to allow customer choice and foster a competitive market for electricity. The Cooperatives believe that any standardized process should be applicable to the very large investor-owned Affected Utilities, Arizona Public Service Company ("APS") and Tucson Electric Power Company ("TEP"), who have large non-rural customer bases. A standardized process is also appropriate for Salt River Project ("SRP"), which is voluntarily and actively participating in the PSWG process although not regulated by the Commission. The Cooperatives believe the vast majority of electric competition will take place in the service areas of APS, TEP and SRP.

In contrast to the service areas of APS, TEP and SRP, the service areas of the Cooperatives are rural. Industrial and large commercial users, those who have the most to gain from deregulation because they

use large amounts of electricity, represent an extremely small segment of total cooperative members, (less than one percent). The Cooperatives serve over 135,000 consumers in their respective service areas, however they have less than 12 customers per mile of distribution line. Thus, although the standardized processes being developed by the PSWG are appropriate for APS, TEP and SRP, these standardized processes are something that the Cooperatives may not be able to implement without placing a significant cost burden on the residential and small commercial cooperative ratepayers.[1]

It must be explained that a significant difference between the cooperatives and the other Affected Utilities, other than their rural service areas, is the fact that the owners of the cooperative are the ratepayers. Thus, all costs incurred by a cooperative are paid by its members/consumers. Other than debt incurred for capital improvements, a cooperative's only source of funding is ratepayers. The objective of the cooperatives is to provide the lowest cost of service without sacrificing reliability in rural Arizona where consumer density is very low compared with the other Affected Utilities. Therefore, the objective of the Cooperatives is to provide retail members with direct access choice in a manner that will not result in cost increases for all UDC consumers. The Cooperatives believe that in some cases, process standardization will result in increased costs to consumers. Members who opt for Standard Offer service should not bear the costs of implementing competition so ESPs costs of doing business are reduced or profits increased.

In conclusion, this summary is intended to put the parties on notice that the Cooperatives are diligently reviewing the draft reports currently being distributed by the PSWG. The Cooperatives will determine whether certain aspects of the processes being developed by the PSWG may need to be varied slightly in regard to the rural electric cooperatives. Accordingly, as the Cooperatives' review the draft reports from the various sub-committees of the PSWG, the Cooperatives will follow-up this summary letter with comments, which the Cooperatives believe should be integrated into the final reports to be delivered to the Commission.

[1] It is important to point out that the Cooperatives have been making a diligent effort to be involved in the PSWG committee and sub-committee activities. However, because of staff size limitations and travel distances, the cooperatives have not been able to attend every meeting and be involved in all discussions. This lack of attendance by all of the cooperatives should not be interpreted as lack of interest. Nor should the cooperatives' silence on any issue be interpreted as consent.

CURRENT STATUS OF THE DIRECT ACCESS PROGRAM IN ARIZONA

The need for process standardization of transactions in Arizona is strong for all market participants. While ***total*** standardization may not be feasible at this time, progress toward standardization will help to encourage a more viable competitive market than currently exists and will allow all market participants to be more efficient in processing transactions. Lack of standardization significantly raises the cost barriers for new entrants to the market. Process standardization will be an ongoing effort as competitive activity increases. To put the current market in perspective, it is important to understand the current level of competitive activity in Arizona.

As of May 1, 2000, activity in the competitive marketplace has been extremely limited. At present, there are 16 companies that have applied for and received their Certificate of Convenience & Necessity (CC&N) to provide competitive services in the state and another 6 with applications pending. As the table below indicates, only 5 of the 16 certificated providers are actively providing any competitive services to customers at the present time. Of the 5 active providers, only 2 are Electric Service Providers (ESP) that provide electric service directly to end-use customers. The other 3 companies provide metering and meter reading services to customers through the 2 ESPs.

Type of Provider	Applied	Certificated	Active (1)
Electric Service Provider (ESP)	14	10	2
Meter Service Provider (MSP)	5	4	1(2)
Meter Reading Service Provider (MRSP)	5	4	3(2)
TOTAL	**22***	**16***	**5**

Despite the fact that the Affected Utility markets have been open to competitive choice for anywhere from 2 to 16 months, depending on the service territory, customer-switching activity has also been extremely limited. Of the 20% of customer load that is presently eligible for competitive choice, approximately 2.5% ***of the eligible MWs*** have been switched to a competitive provider to date. All of the switching to date has been by business customers, as no residential customers are currently being served by a competitive provider. The approximate competitive activity by major utility service territory is shown in the table below.

	APS	**SRP (3)**	**TEP (4)**	**Citizens & AZ Coops**	**TOTAL**
Open for competition	Dec. 1, 1999	Dec. 31, 1998	Mar. 1, 2000	Not Open	
# of ESPs certificated	2	1	0		2
# of MRSP/MSPs certificated	4	0	0		4
# of MWs eligible	885	814	324		2,023
# of MWs switched *	46	0	0		46
% of eligible MWs switched	6%	0	0		2.5%

This low level of activity thus far in Arizona, suggests that a truly robust competitive market has not yet developed and efforts to standardize competitive processes should be ongoing to facilitate further market participation.

*Columns do not add to TOTAL because 2 providers are listed as both an MSP and an MRSP.
** As of May 1, 2000
(1) Defined as currently providing competitive services to at least one direct access customer.
(2) Provide service to customers through the ESPs.
(3) SRP had 4.5 mW switched to an ESP from June 1999 to May 2000
(4) 3 companies are in the process of becoming certified with TEP

BACKGROUND AND PURPOSE

The first meeting of the Process Standardization Working Group (PSWG) was held December 3, 1999. At this meeting Ron Franquero brought everyone up to date on the work that had already been done towards standardization.

The second meeting was held on January 7, 2000. Deb Scott led the meeting. The facilitators from City of Mesa were introduced along with the Chairman Evelyn Dryer. The participants of the working group developed goals for the successful conclusion of its charge.

PSWG Goals and principals:

- The process will have occurred on a level playing field.
- There will be complete and total participation and involvement from everyone.
- The process will set a positive example of partnership in developing important business rules.
- There will be positive relationships throughout and following the process.
- The process of collaboration will continue after June 15, 2000.
- The products will be satisfactory to everyone involved.
- The proposals will be cost-effective.
- There will be no time wasting.
- There will be real partnerships developed as a result of the process.
- The products will be ‘down to earth’ and practical.
- There will be excellent communication among the parties involved in the process.
- The process will result in actual, experimental, real world prototype business processes.
- The group and its subcommittees will have exercised good judgment.
- There will be open architecture.
- We will be able to have such a clear product that subsequent rule making will be easy, quick, and to the point.
- The proposals developed will be flexible enough to adapt to change.
- Others who judge the process and its results will say that the group did a great job, the antithesis of the ‘telephone experience’.
- The products recommended will be balanced and fair.
- There will be a team formed for ongoing implementation issues, based on the example set by this process as an effective way for a group to address complex, controversial issues.
- The process will have been challenging, fair, fun, and frustrating.

- The products are so clear and fair that the participants do not have to defend their actions against naysayers.
- The vast majority of the participants are happy with the products of the group effort.
- The group stayed focused during its deliberations.
- There is clarity in how all the recommended business processes, electronic platforms, and policy issues that still need resolution articulate with one another.
- As a result of the group's recommendations, electric deregulation can be implemented without costing the customer 'an arm and a leg'.
- There are cordial, professional relationships and partnerships developed between competitors.

The work group then went on to develop operating Principles, Ground rules, and Voting Qualifications. Voting qualifications were needed to prevent the process from being mired in indecision, but the group determined that a consensus on issues would first be sought.

PSWG Principles, Ground rules, and Voting Qualifications:

Operating Principles	1. The interests of all stakeholders will be considered, irrespective of their presence. 2. The group will be open to new ideas, processes, and ways of doing business. **3. "Best Practices" will be used as resources in guiding the recommendations of the group and its subcommittees.** 4. Recommendations should consider the economic consequences to all market participants. 5. All market participants must utilize the format that is recommended by the group. 6. The group will be open to reinventing processes. 7. The group will agree to a solution and/or set of recommendations for each process. 8. The group and its subcommittees will operate by consensus insofar as possible.
Meeting Ground Rules	1. The results of the group's deliberations will be shared openly and in a timely manner with all market participants. 2. The PSWG will revisit decisions made at a previous meeting, using the guidelines of its established change control process. 3. Implementation issues will be documented and discussed in the group's final report, separate from recommendations on process standards. 4. The group will develop recommendations and a proposed timeline for both interim and long-term process standardization changes. 5. . Meeting agendas will be adhered to. New issues will be calendared for future meetings.
Voting Qualifications	1. Subcommittees: 75% majority of those in attendance will be required to move an issue to consideration by the full group. 2. Full Group: A simple majority will hold sway on issues. 3. A person can vote, either at the subcommittee or group level, if: ▪ He/she [or the organization he/she represents] is bound to live with the vote Or ▪ He/she [or the organization he/she represents] has a CC&N pending or approved by the ACC Or ▪ He/she represents an affected utility or are under the jurisdiction of the ACC AND ▪ He/she has been an active participant in the work group [through presence or via electronic means]. 4. Each voting person shall have one vote. No voting entity shall have more than one voting person. 5. SRP may vote if they produce a letter from SRP management indicating the organization's intent to be bound by ACC rules affecting electric deregulation.

Additionally at this first meeting it was determined to create five subgroups, DASR, Billing, Metering, Policy, and Remittance and Error Processing. Only three of the five subgroups have been meeting due to the amount of work needed and the limited number of participants.

Since the initial meeting, the subgroups met on a weekly or bi-weekly basis.
The PSWG meetings were held on January 7th, February 23rd, May 3rd, May 17th, and May 31st. The City of Mesa has been providing, free of charge, facilitators for all of the meetings. The facilitators have been an asset to the process, and the PSWG participants would like to have continued facilitation for this process. The City of Mesa will no longer be able to provide facilitators after June 2000.

The participants of the PSWG have learned much from each other. Each one of the different entities brings important information to the table. The group to date has completed much work. The PSWG participants believe it is important for the work of the group to continue beyond this report to continue to standardize Direct Access processes. Members feel that to have a viable market in Arizona this work is essential.

Policy Subcommittee Report

Process Standardization Working Group (PSWG)- Report

Subcommittee Charge

Charge	Throughout the duration of the PSWG, serve as a clearinghouse for discussion, coordination, and clarification of policy issues that need to be addressed by PSWG. Additionally, develop a change control process to be used by PSWG in its decision-making processes, and address security and transport issues related to electric deregulation.
Deliverables	1. Develop and recommend an on-going market change control process to be utilized by the ACC and the market participants. 2. Provide oversight and make recommendations to the PSWG on security issues related to electric deregulation business transactions. 3. Conduct research and provide guidance to the PSWG on transport issues embedded in the proposed electric deregulation business transaction processes. 4. Identify and communicate to PSWG policy issues that need resolution in order to guide subcommittee deliberations or PSWG recommendations.

Overview of Status

Item	Status	Where Found in Report	Notes
1. Develop and recommend an ongoing market change control process to be utilized by the ACC and the market participants.	Addressed but not completed yet.	NA	
2. Recommend to the PSWG on security issues related to electric deregulation business transactions.	Not yet addressed.	N/A.	
3. Recommend to the PSWG on transport issues embedded in the proposed electric deregulation business transaction processes.	XML was thought to be a transport mechanism but it is only a different format type.	Pg. 21	See individual issues for required actions.

Item	Status	Where Found in Report	Notes
4. Identify and communicate to PSWG policy issues that need resolution in order to guide subcommittee deliberations or PSWG recommendations.	The majority of the subcommittee's work has been focused on this objective.	Throughout the subcommittee report.	

Summary

The Subcommittee's report contains information specific to issues that were presented by market participants. The subcommittee prioritized the issues depending on the immediacy of need.

The recommended resolutions in this report will have issue, resolution or discussion, market benefits; implementation plans and, where applicable, market participants' positions. Additionally, the following table will identify if the proposal is: 1) a business process that has consensus standardization between the UDCs and the Providers which requires **NO** Commission action or 2) a proposal that requires Commission action (i.e. Rule, Waiver, operational procedure or UDC Tariff change).

Issue #	ACC Rule	ACC Operating Procedure	UDC Tariff	Business Process No ACC action required.
26				X
27	R14-2-1612 (K)(12)			
56	R14-2-1615 (B)(1)			
48				X
34				X
77		MSP Procedure		
46		MRSP Procedure		

The following steps were used to develop and address issues:

1. All market participants were invited to identify policy and implementation issues.
2. The Subcommittee solicited position papers from interested participants.
3. The Subcommittee determined what rules, tariffs, and or operating procedures appeared to be affected.
4. The Subcommittee developed recommendations, waiver requests, and/or documented issues with no resolution.

Issues Resolved

Issue #26: XML versus EDI

These are data formats used to electronically transfer data. Which should be used for the Arizona market? (Appendix P1 for XML-EDI White paper.)

Resolution:

EDI will be the format used to electronically transfer data.

Market Benefits:

There are not any applicable versions of XML in use at present time. Market participants are using EDI and formats needed for Direct Access have been created by the Utility Industry Group (UIG) and others.

Implementation Plan:

The PSWG is in the process of developing EDI formats for use in Arizona's market. As each implementation and user guide is completed the market participants will be given a time line for implementing the specific format.

Arizona also needs to keep XML on it radar screen. **The Retail Electric Competition rules R14-2-1612 (K)(4)**

> Current Rule: Unless the Commission grants a specific waiver, all competitive metered and billing data shall be translated into consistent, statewide Electronic Data Interchange (EDI) formats based on a standards approved by the Utility Industry Group (UIG) that shall be used by the Affected Utility or the Utility Distribution Company and the Electric Service Provider.

No ACC action is required at this time.

Issue # 27: Standardized Work Day

Market participants are defining 'workdays' for time frames to determine when work will be completed. The problem is that some companies are including holidays that are not recognized by others.

Resolution:

Market participants and UDCs will standardize their definition of workday using a modified NERC holiday schedule. The modification is needed, as NERC holidays do not take into account weekends. The modification required is if a NERC holiday falls on a Saturday, it will be recognized on a Friday, if the holiday falls on a Sunday, it will be recognized on a Monday.

Market Benefits:

Most of the providers of retail service are not seven (7) day-a-week operations. These include billing, metering, meter reading, and DASR services. Recognizing holidays on the day they are officially observed will ensure consistency between all market participants in the calculation of working days for any processes with specific time requirements.

Implementation Plan:

A change in rule R14-2-1612-(K)(12) is required.

> Current Rule: North American Electric Reliability Council recognized holidays will be used in calculating "working days" for meter data timeliness requirements.
>
> Revised Rule: The North American Electric Reliability Council recognized holidays will be used in calculating "working days" for meter data timelines requirements. With the following modification that if a holiday officially occurs on a Saturday, the proceeding Friday will be recognized as the date of the holiday. Likewise, if a holiday officially occurs on Sunday, the date of observance will be the following Monday

In the interim, PSWG participants will be applying for wavers. (Appendix P2 Waiver for Workdays.)

Issue # 56: Commercial Load Profiled Meter Services

Current ACC rules prohibit UDCs from providing metering services for commercial load profiled customers, with the exceptions of cooperatives operating in their own service territories. This has the effect of preventing these customers from having a choice. Providers agree that it is too costly for alternate providers to read the meters at the premises. It is also not cost effective to put remote read meters at these premises and this is why UDCs were allowed to load profiled.

Resolution:

Allow UDCs to provide MSP and MRSP services for commercial load profiled customers.

Market Benefits:

Gives small commercial customers retail choice.

Implementation Plan:

A change in rule number R14-2-1615-(B)(1) is required.

> *Current Rule: This Section does not preclude an Affected Utility or Utility Distribution Company from billing its own customers for distribution service, or from providing billing services to Electric Service Providers in conjunction with its own billing, or from providing Meter Services and Meter Reading Services for Load Profiled residential customers.*
>
> *Revised Rule: This Section does not preclude an Affected Utility or Utility Distribution Company from billing its own customers for distribution service, or from providing billing services to Electric Service Providers in conjunction with its own billing, or from providing Meter Services and Meter Reading Services for Load Profiled residential or commercial customers.*

In the interim, the Affected Utilities will be applying for waivers. (Appendix P3 Waiver for Load Profiled Meter Services)

Issue # 48: Rounding of billing and metering data

For all billing and metering data, UDCs should employ the same rule and/or formula for rounding up data and rounding in calculations.

Resolution:

No standardization needed because the PSWG found that these issues were not widespread and the magnitude is fairly small. The metering and billing groups will look at this issue as they go through the different transactions.

Issue # 34: Reporting meter exceptions

There is no formalized process to report meter exceptions between UDCs and ESPs.

Resolution:

It has been agreed that a formal communication method modeled after the MADEN process in California will be utilized.

Market Benefits:

A structured communication process among market participants is necessary so problems can be corrected prior to customers receiving incorrect bills.

Implementation Plan:

The details of what data elements/guidelines are required will be discussed in both the metering and billing subcommittees.

Issue # 77: Requiring Universal Meter Identifier (UMI) numbers

The UMI was presumed to be the national standard for identifying a single meter. However, it is not being used by any other state in the deregulation market. Furthermore most of the EDI documents are not implementing a UMI number.

Resolution:

Arizona should not implement the UMI.

Market Benefits:

It will save all of the market participants the cost of implementation and will not create any problems in the process.

Implementation Plan

A letter will be given to the Utilities Director asking for the removal from the operational procedures of the requirement to use the UMI standard. (Appendix P4)

Issue # 46: Use of standardized times for business transactions

All Arizona EDI (814, 867, 810, 650) should use a standard time for business transactions. This will help to avoid problems and unnecessary costs to conform to national standardization in the future.

Resolution:

All Arizona EDI transaction set data content will utilize GMT. The enveloping of the EDI transactions will utilize the sender's local time.

Market Benefits:

This change would help market participants, particularly MDMAs/MRSPs, by not having to adapt their systems to Arizona's unique requirements. In addition, it may prevent errors during settlement process.

Implementation Plan:

This will require a change in the ACC Direct Access Operating Procedures that are approved by the Utilities Director. A letter signed by all PSWG participants will be sent to staff asking that this be done. (P5 Change Time stamp.)

Issue # 18: Customer Bill Line Items

For End Use Customer billing (dual billing situation) the ACC Rules are not specific about the responsibilities of what the utility is obligated to show on their bill and what the ESP is obligated to show on the bill.

Resolution:

The bill party needs to itemize the bill components to allow customer to break down / re-calculate the bill.

Market Benefits:

Customers will receive bills with line items that are appropriate for the charges being billed.

Implementation Plan:

A change in rule number R14-2-1612 (N) is required.

> *Current Rule: Billing Elements. After the commencement of competition within a service*

territory pursuant to R14-2-1602, all customer bills, including bills for Standard Offer Service customers within that service territory, will list, at a minimum, the following billing cost elements: 1. Competitive Services: a. Generation, which shall include generation-related billing and collection; b. Competition Transition Charge; c. Transmission and Ancillary Services; d. Metering Services; and e. Meter Reading Services. 2. Non-Competitive Services: a. Distribution services, including distribution-related billing and collection, required Ancillary Services and Must-Run Generating Units; and b. System Benefit Charges. 3. Regulatory assessments; and 4. Applicable taxes.

Revised Rule: Billing Elements. After the commencement of competition within a service territory pursuant to R14-2-1602, all customer bills, including bills for Standard Offer Service customers within that service territory, will provide specific line items identifying all components of a customer's bill for which that entity provides service.

In the interim, the affected utilities will be applying for waivers. (Appendix P6 Waiver for Bill Line Items)

Issues Outstanding

Issue #	Content/Comments
44	Ownership of Current Transformers (CTs) and Voltage Transformers (VTs) and related issues.
29	Are 997s required for all transactions?
56	Non-availability of local alternatives for providing competitively priced metering services.
28	Clarification on when a UDC can be an MSP. ACC Rules Question: Can the UDC provide metering and installation services for DA customers?
52	UDCs and market participants need a clearly defined communication process for promptly communicating and

resolving problems with data, meters, or bills among ESPs, MSPs, MRSPs, and the UDCs.

38 Will the UDCs allow ESPs to interrogate meters on non-DA customers for load research purposes/ billing option purposes?

47 Standardization of Billing Options (ESP and UDC consolidated billing as well as dual billing) from all UDCs should be implemented immediately to provide customer choice.

55 UDC fees for Direct Access services (CISR, DASR, metering, meter reading, billing, settlement, etc.) are too high and not consistent between UDCs.

61 Who is responsible for tracking the performance of MSP and MRSPs? What is the process for communicating this information?

69 What is the enforceability of the recommended processes or rules of non-ACC jurisdictional entities?

70 A utility can back-bill a 3rd party (if the 3rd party is at fault) up to 12 months (R14-210-(E)(3). This is only specific to the utility. Should the rule be applicable to other participants other than just the utility?

78 There is no language in the rules keeping the MSP from contracting directly with the customers.

Billing Subcommittee Report

Subcommittee Charge

Charge	Develop recommendations to the Process Standardization Working Group on content of proposed business transactions and electronic transmission related to billing information, including transaction errors. Discuss and seek consensus on billing related issues raised by market participants related to the implementation of Direct Access.
Deliverables	1. Recommendations on transaction processes. 2. Recommendations on the electronic platform[s] that are desirable to accomplish these processes. 3. Short-term implementation recommendations. 4. Long-term implementation recommendations. 5. Any other policy, procedural or content recommendation germane to the focus area.

Overview of Status

Item	Status	Where Found in Report	Notes
Description of Best Practices	Partially completed.	Page 33 – 34	Focus has been of ESP Consolidated Billing
Description of Ideal Business Practices in AZ	Partially completed.	Page 35 – 37 Page 38 – 40	Cancel Re-bill Notification Billing Error Notification
Description of Ideal Data Element Requirements	Partially completed	Page 41 – 42	Data Element requirements for ESP Consolidated Billing
Flowchart of Ideal Business Practices	Not Started		
Description of Current Practices	Completed.	Appendix B-C	Comparison of current UDC practices.
Billing Issues	Several Issues Resolved.	Appendix I	Subcommittee has resolved some issues. In some cases, ACC action is recommended. In other cases, ACC action is not needed because the issue is a business decision by one or more of the market participants.

Process Standardization Working Group (PSWG)- Report

Group Charge

Develop recommendations to the PSWG on content of proposed business transactions and electronic transmission related to Consolidated Billing and Settlement with Scheduling Coordinators.

Objective

Produce an accurate, timely and understandable bill to the end use customer. The group objective is to recommend transaction processes and timeline, including but not limited to:

- Develop short-term implementation recommendations (e.g. suggestions for a workaround, if applicable)
- Identify best practice in implementation recommendations (e.g. ideal process) This includes Electronic Data Interchange (EDI) implementation guide and implementation schedule.
- Create policy, procedural or content recommendation related to the transaction.
- Share billing information between the various market participants
- Achieve consistency throughout the market place.

Steps To Achieve Best Practice

The subcommittee members (Appendix B-D) conducted the following steps:

1. Flow chart current business process of APS, SRP, TEP, TRICO, Citizens and APSES
2. Identify related policy and implementation issues
3. Flowchart of the ideal process(es)
4. Identify the current consistent and inconsistent processes
5. Identify what processes are desired and what processes are acceptable
6. Identify best practices and related documentation, using operating principles as guidelines.
7. Recommend to PSWG the best model for these transactions for the Arizona Market
8. Develop recommendations on related policy, implementation issues and timeline.

Summary

The group was faced with significant challenges due to the following:

- Existing utility systems were not designed to work with external systems
- Direct Access requires new ways of operating with existing systems and business practices

- Direct Access requires significant resources (cost and time) to make changes to UDC and ESP systems to serve the current market demand
- The Arizona Co-Operatives have unique circumstances with respect to Direct Access due to size, location of territory, customer base, and resource constraints

The group identified and prioritized five Direct Access Billing Functions including ESP Consolidated, UDC Consolidated, True Up & Settlement Statements, True Up and Settlement Invoices, and Bill to End Use Customer. Anticipating market needs, the group prioritized the ESP Consolidated Billing as the first billing transaction to be addressed.

Identification of major/critical issues related to ESP Consolidated Billing was another step. Issues were defined as questions, concerns, and/or lack of clarity in protocols or rules. Processes that had not been identified in the original protocols, rules and procedures were also addressed. The issues were prioritized and worked accordingly. Resolved and Unresolved Issues are located in Appendix I.

Accomplishments:

- Recommended several processes of standardization (outlined in greater detail within this report)
- Avoidance of costly changes to systems for both the ESP and UDC with interim solutions
- Identification of items that were not originally covered
- Resolved 16 out of 27 issues
- Resolved all “current” high priority issues pertaining ESP Consolidated Billing
- Gained a common understanding of current operating processes
- Reached agreement on data elements for standardization of the EDI 810. The 810 transaction is an electronic exchange of data between the UDC and the ESP, which allows the ESP to produce a customer’s bill with the UDC charges.

Remaining Work

- Complete unresolved issues relating to ESP Consolidated billing
- Recommend and finalize EDI 810
- Complete billing functions (UDC Consolidated, True Up and Settlement Statements, True Up and Settlement Invoices, and End-use Customer)

- Continue to identify and conduct an in-depth analysis of Rules, allowing for flexibility of market systems and interim solutions for Direct Access billing

The Billing subcommittee has made tremendous strides in accomplishing its goals and will continue to work to achieve the goals and objectives set forth in PSWG. The group still has a great amount of work to be completed and will continue to pursue the best billing processes for the Arizona Market.

As of the date of this report, we are recommending the following processes, outlined below, for standardization:

B 1. ESP Consolidated Billing
B 2. Interim Re-Bill Data
B 3. Billing Exception Notices (BEN)
B 4. EDI 810 Transaction

Detail of B.1 - ESP Consolidated Billing

Purpose
ESP Consolidated billing is used when the ESP is the primary biller, allowing the Direct Access Customer to receive one bill. The customer bill includes the UDC charges and the ESP charges. The ESP is responsible for paying the UDC for UDC charges.

Description - Summary of "as is" ESP Consolidated Billing

The table below lists all the steps in the current ESP Consolidated billing processes. The table below shows what has been identified as common processes, processes that can remain inconsistent and differences that a consistent process should be agreed upon among the Utilities with respect to ESP Consolidated Billing

Common Elements and Processes that can remain inconsistent	Differences - Pending or Unresolved
▪ Bill is generated ▪ Require meter reads to bill ▪ Multiple parties reading meters ▪ All parties are performing some sort of validation of meter and billing data ▪ UDC is not required to pay ESP receivables ▪ ESP is required to pay ESP receivables ▪ ESP is required to pay UDC ▪ All UDCs tie customer to a cycle ▪ All parties relying on Electronic Data ▪ All parties bill in US currency only ▪ Rate Structure ▪ Number of Cycles ▪ Due dates on bills	▪ Business Vocabulary ▪ Billing Credit for Rebate Rebill(how and when, minimum) ▪ Rebates (how and when, minimum) ▪ Validation Rules/processes are different ▪ Define customer to a class ▪ Switch billing options meter and billing data ▪ Time frame between read date and bill date ▪ Data Transport Mechanism (Van, Exolink, Internet EDI, e-mail) ▪ Data Security ▪ How and when data are estimated and who does it ▪ Disconnect/Reconnect ▪ Cancel Original Bill and re-bill ▪ Non-pay ▪ Final Bill ▪ Back Bills ▪ Meter Tampering / Energy Theft ▪ Delivery timeframes for bill ready data to ESP ▪ Dispute Resolution process for Meter Reads ▪ Bill inserts and how delivered to ESP ▪ Data File format

The following are issues that the Billing Group agreed to be standardized with respect to ESP Consolidated Billing Process

Standardization	Requirements	ACC Action Required	Agreement
ESPs are not required to bill customer for non-utility charges such as security systems, internet by the Utilities	Process Change No Barriers	None	Consensus
The UDC will provide the UDC emergency contact number and Arizona Corporation Commission number to the ESP at the time of certification with the UDC. It will be the ESP's responsibility to include this information with each customer billing transaction	Process Change No Barriers	None	Consensus
The UDC will not pass the same month last year and prior month consumption data for usage graph purposes for ESP Consolidated Billing	Process Change No Barriers	None	Consensus

Benefits of the above solutions

- Streamlined Direct Access bill for the customer
- Transactional costs are reduced
- The practices recommended are standard practice in CA and other states.

Implementation Plan

- There are no implementation barriers
- The process has already been implemented

Next Steps

- These changes will be incorporated when the Arizona Standard ESP Consolidated Billing Transaction (EDI 810) is implemented.

Detail of B.2 – Interim Cancel/Re-Bill Data Process

Purpose

Rebilling occurs when it is necessary to adjust a previous bill to the customer. The current billing transaction from the UDC may not provide enough detail for the ESP to provide a timely bill to the end use customer. The circumstances under which a customer may be re-billed include but are not limited to the following scenarios:

1. Usage Related
   - Original Bill was estimated, actual data is now available
   - Meter Tampering
   - Meter not calibrated, dead meter, bad multiplier
2. Rate related
   - Rate Change
   - Incorrect rate calculation
3. Non–usage related
   - Tax (flat rate, tax changes)
   - Cycle Change

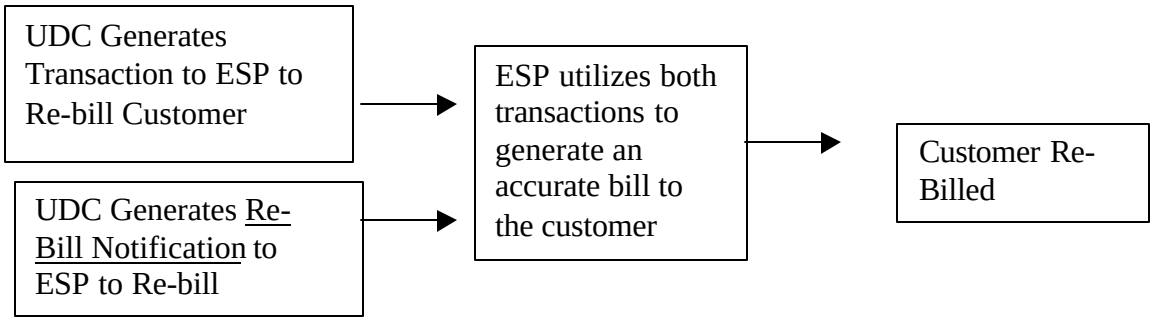
Until a standardized EDI810 transaction process and necessary system changes at each UDC are implemented, the group has agreed to implement the re-billing process for the Customer.

Issues with current processes

- Interim electronic process does not provide data from UDC to the ESP to accurately and efficiently re-bill the customer.
- ESP receives the current interim invoice transaction from UDC coded as a re-bill with an amount but UDC does not provide the time period or amount for the periods being credited
- ESP manually determines the time periods and amount - time consuming and may or may not be as the UDC intended to be re-billed because ESP has no information.
- Manual process causes billing to be delayed to the customer.
- ESP may incur late charges from UDC for non-payment under ESP consolidated billing because it cannot validate invoice due to the manual process or lack of information.

The following is summary of the Re-Bill Data Notification:

Interim Cancel/Re-Bill Process – ESP Consolidated Billing



Purpose

- **Intended as an interim measure to ensure timeliness and accuracy of the customer bill by both the ESP and UDC**
- **Avoid disputes between the ESP and UDC for late charges**

Cancel/Re-Bill Notification Requirements

- **Notification is sent to the ESP or as designated by the ESP**
- **Transport method is in Comma Separated Value (CSV) or Excel format**
- **Posted or by e-mail in the agreed format for each re-billing**
- **Multiple re-billing can be batched in one file or single files**
- **Notification would be sent to the ESP on the same transaction date as the original rebill transaction or no later than 24 hours**

Data		**Field Description**	**Field Info.**
1	Date of original EDI transaction	The date the original transaction was sent to the ESP	To be determined (TBD)
2	UDC Account Number	The account number assigned to the customer by the UDC	TBD
3	UNI #	Number assigned by UDC	TBD
4	Reason Code Estimated vs. Actual Multiplier Error Tampering Rate Tax Other: ACC Miscellaneous T & D, Fuel Adjustment etc.	Reason for the Cancel Re-Bill; Reason for consumption difference (most common)	TBD
5	Date Adjustment passed to the ESP	The date the actual transaction was transmitted to the ESP	TBD
6	Bill Date	Original Bill Date (810)	TBD
7	Meter #	The meter # for that read	TBD
8	Bill Cycle	Start/Stop, to/from information	TBD

Data		Field Description	Field Info.
9	Consumption	Original (Optional) New	TBD
10	Dollars applied to each time period (time periods identified)	Dollars applied to each	TBD

Benefits

- Customer bill delivered on a timely basis
- Billing is accurate and agrees with UDC bill
- Bill presentation is more understandable to the Customer

Implementation Plan

- As of the date of this report a time line has not been agreed upon.

Next Steps

- To be determined when implementation plan has been developed.

B. 3. Billing Exception Notices (BEN) Process

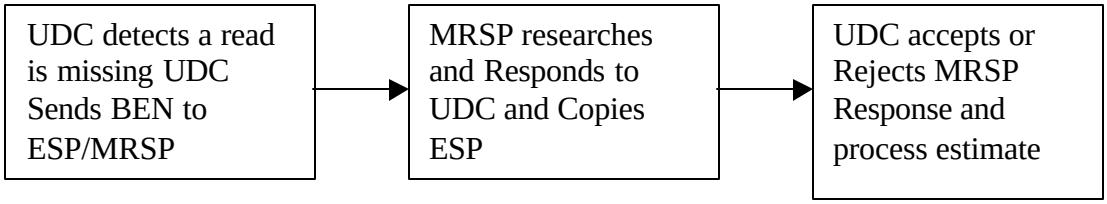
Purpose

The Billing Exception Notice process is intended to manage EXCEPTIONS that prohibit or impede customer billing by the UDC or the ESP. An example of an exception is Missing Meter Reads or Missing intervals. Reasons for these data exceptions are the implementation of remote meter reading equipment and data being reported in a new format (EDI 867). This is an interim process until the PSWG develops a standard mechanism for error notification. It is a communication that allows problems to be resolved timelier.

Issues

- Historically in a new DA Market meter reading issues surface for many reasons which include but not limited to
  - Meter communication issues
  - Lack of understanding or clarity of Market requirements
  - System complexities due to market standards or requirements
- The MRSP issues result in missing reads, missing intervals, etc. which in turn result in estimation of the customer's bill and then subsequently Cancel/Re-billing.
- In order to avoid delayed or estimated bills to the customer, notification and an opportunity to correct the data should be an option for the ESP and MSRP.
- Currently, the ESP/MRSP is not notified in a timely basis that the read is missing by the UDC and in some cases not given the opportunity to get an actual read before the UDC estimates the bill.
- The MRSP may have posted the read but failed in syntax or data content or other technical difficulties with the meter.

Interim Billing Exception Notice (BEN) Process



Purpose

- **This process enables all parties to bill on actual data within the existing time frame required to bill.**
- **Reduces transactions costs of re-billing**
- **Avoids customer confusion due to rebilling**

Billing Exception Notification Requirements

- **Notification will be sent to the ESP/MRSP or as designated by the ESP**
- **Standard Subject Line if sent by e-mail.**
- **Transport method is in CSV or Excel format**
- **Posted or by e-mail in the agreed format for each exception**
- **Multiple exceptions can be batched in one file or sent as single files**
- **Notification would be sent to the ESP/MRSP as soon as an issue is detected or a minimum within 24 hours**
- **Estimation will occur as follows:**
  - **APS will notify the ESP of the exception SRD +7 days and the exception response is due to APS on the SRD +11 days.**
  - **TEP will notify the ESP of the exception SRD +2 business days and the response is due from the ESP 4 calendar days from SRD.**
- **BEN remains open until delivering of actual data**

Data		**Field Description**	**Field Size & Type** **N= Numeric** **A= Alpha**
1	UDC Account Number (new)	Required	**20 N**
2	UDC Account Number (old)	Optional	**20 N**
3	Meter Number	Required	**20 A/N**
4	ESP Account Number	Required	**20 A/N**
5	MRSP Name	Required	**50 A/N**

Data		Field Description	Field Size & Type N= Numeric A= Alpha
6	Reason for the Problem Identification - Missing Data/No Data - Missing Interval(s) - Invalid file format - Usage Demand out of normal range - Missing 810 Transaction - Meter Malfunction	Required	**64K A/N**
7	Action Required	Optional	**64k A/N**
8	Due Date for Action	Required	**10 N**
9	Comment Field	Required	**64k A/N**
10	Last Good Data Received	Conditional (if available)	**10 N**

Benefits

- Customers bills delivered on time
- Accurate billing
- Avoids re-billing the customer
- Effective way to track communication
- Deadlines are set and pre-determined actions are known

Implementation Plan

- As of the date of this report a time line has not been agreed to.

Next Steps

- To be determined when implementation plan has been developed.

B. 4 EDI 810 Transaction

Purpose

To facilitate ESP Consolidated billing a standard method for delivering the UDC bill information to an ESP needs to be developed. In other states a standard EDI 810 transaction has been developed. This standardization allows an ESP to gain efficiencies in their billing system.

Issue

As of the date of this report APS is the only UDC that has a published 810-implementation guide for ESP Consolidated Billing. This guide was developed using the Utility Industry Group (UIG) as a model. Currently there are other business standards groups developing guidelines. The Billing Sub-Group needs to review these guidelines and develop an Arizona standard.

The following table shows all billing data elements that have been identified. The Coalition for Uniform Business Rules (CUBR) model and APS' model. This matrix needs to be completed and an Arizona guideline developed.

ESP Consolidated Billing Field Comparisons --

Field	AZ EDI Proposed	CUBR EDI	APS EDI
ACC Contact Number		H-030 NTE	
ACC Regulatory Assessment	D-180 SAC	D-180 SAC	D-230 SAC
Account Balance(prior)	D-180 SAC	D-180 SAC	S-040 SAC
Basic service charge	D-180 SAC	D-180 SAC	D-230 SAC
Beginning Read	D-059 MEA		D-059 MEA
Bill Message	H-030 NTE	H-030 NTE	
Billing Address	H-090/100 N3/N4		
Billing Charge (BAS001)	D-180 SAC	D-180 SAC	D-230 SAC
Billing Date	H-020 BIG	H-020 BIG	H-020 BIG
Billing Status (Final Bill)	H-020 BIG	H-020 BIG	H-020 BIG
City Tax (Sales tax)	D-040 TXI or D-190	D-040 TXI or D-190	D-040 TXI
Competitive Transition (MSC022)	D-180 SAC	D-180 SAC	D-230 SAC
County Tax (Sales Tax)	D-040 TXI or D-190	D-040 TXI or D-190	
Customer Name	H-050 N1	H-050 N1	D-240 N1
Customer Store Number			
Distribution Deliver Charge (DIS001)	D-180 SAC	D-180 SAC	D-230 SAC
Due Date	H-130 ITD		H-130 ITD

ESP Consolidated Billing Field Comparisons --

Field	AZ EDI Proposed	CUBR EDI	APS EDI
Ending Read	D-059 MEA		D-059 MEA
Flat Rate Charge based on service			
kW Demand			D-059 MEA
kW Maximum Range	D-059 MEA		D-059 MEA
kW Minimum Range	D-059 MEA		D-059 MEA
Meter Number	D-120 REF	D-120 REF	D-120 REF
Meter Ownership Charge			
Meter Read Charge (SMD016)	D-180 SAC	D-180 SAC	
Meter Read Cycle	D-120 REF		D-120 REF
Miscellaneous Charges	D-180 SAC	D-180 SAC	
Multiplier Value	D-059 MEA		D-059 MEA
Number of Days in billing period			D-120 REF
Off Peak Usage			
On Peak Usage			
Period End	D-150 DTM	D-150 DTM	D-150 DTM
Period Start	D-150 DTM	D-150 DTM	D-150 DTM
Rate Code	D-120 REF	D-120 REF	D-120 REF
Regulatory Assessment (SUR000)	D-180 SAC		D-230 SAC
RUCO Regulatory Assessment			
Franchise Fees (ADJ006)	D-180 SAC	D-180 SAC	
Service Address	D-260 N3		D-260 N3
Shoulder Peak Usage			
State Tax (Sales tax)	D-040 TXI or D-190	D-040 TXI or D-190	D-40 TX1
Subtotals (Needs definition.)			
System Benefits Charge			D-230 SAC
Total Amount Due (Needs def.)	S-010 TDS	S-010 TDS	S-010 TDS
Total Current Month Charges			
kWh Usage			D-059 MEA
Transformer Credit (CRE004)	D-180 SAC	D-180 SAC	
UDC Account Number	H-050 REF	H-050 REF	H-050 REF
Voltage Credit			
Primary Voltage Credit			D-230 SAC
Transmission Voltage Credit			D-230 SAC

Metering Systems
&
Meter Reading Subcommittee Report

Subcommittee Charge

Charge	Develop recommendations to the Process Standardization Working Group on content of proposed business transactions and electronic transmission related to metering information, including transaction errors. Discuss and seek consensus on metering related issues raised by market participants related to the implementation of Direct Access.
Deliverables	6. Recommendations on transaction processes. 7. Recommendations on the electronic platform[s] that are desirable to accomplish these processes. 8. Short-term implementation recommendations. 9. Long-term implementation recommendations. 10. Any other policy, procedural or content recommendation germane to the focus area.

Overview of Status

Item	Status	Where Found in Report	Notes
Description of Best Practices	Partially completed.	Page 45	Focus has been of switching commercial customer from UDC to DA
Description of Ideal Business Practices in AZ	Partially completed.	Appendix M-8	Focus has been of switching commercial customer from UDC to DA
Description of Ideal Data Element Requirements	Completed	Appendix M-5	Data Element requirements for the initial switch to Direct Access when a meter exchange is involved
Flowchart of Ideal Business Practices	Completed.	Appendix M-9	
Description of Current Practices	Completed.	Appendix M-7	Comparison of current UDC practices.
Metering Issues	Several Issues Identified.	Appendix I	Subcommittee has resolved some issues. In some cases, ACC action is recommended. In other cases, ACC action is not needed because the issue is a business decision by one or more of the market participants.

Group Charge

Develop recommendations to the Process Standardization Working Group on content of proposed business transactions and electronic transmission related to metering systems and meter reading, including transaction errors. Discuss and seek consensus on metering related issues raised by market participants related to the implementation of Direct Access.

Steps to Achieve Best Practice

The subcommittee participants (Appendix M-1) conducted the following steps:

1. Flow chart current business processes by APS, SRP, TEP, Citizens and Co-ops
2. Identify related policy and implementation issues
3. Flowchart ideal processes
4. Identify best practices and related documentation, using operating principles as guidelines
5. Recommend to PSWG the best model for these transactions in the Arizona Market
6. Develop recommendations on related policy, implementation issues and timeline.

Summary of Best Practices

This section of the report contains information specific to metering transactions used between the Utility Distribution Companies and the Providers (i.e. MSP, ESP). The efforts of the subcommittee group thus far have primarily focused around the following process:

Arizona Best Practice #1 - Meter Exchange processes for the initial switch to Direct Access services from Standard Offer services

It was agreed upon by the participants, to start with Best Practice #1 since this is the first metering transaction encountered by the Market Participants. Standardizing this process required the group to examine business processes, Rules and timing requirements that many of the Utilities already have in place. The group also solicited proposals from Providers on how they would like to do business (Appendix M-2).

The AZ Best Practice in this report will have proposed data elements, business rules, forms, or transport mechanisms to be followed in association with each process. Additionally, each section will identify if the

proposal is 1) a business process that has consensus standardization between the UDCs and the Providers which requires **NO** Commission action or 2) a proposal that requires Commission action (i.e. Rule or UDC Tariff change). Additionally, all supporting documentation will be included either in the report or in the Appendix to the report.

Description of Best Practice

Process #1 *Meter Exchange processes contracted with ESP for the initial switch to Direct Access services from Standard Offer services*

When a customer has selected an alternative Electric Supplier in the competitive market, there are several processes that must take place for the customer to switch to the new provider. Depending upon the type or load size of the customer, there may be a requirement for a new meter to be installed by the new provider. The information below for the proposed AZ best practice for this process includes standardization of the:

- Data elements that must be exchanged between Market Participants
- Forms used to exchange the data elements
- Various business rules associated with this process

In the beginning stages of the subcommittee meetings the Utilities presented their existing process flows for this scenario (Appendix M-3). After reviewing the flows, it was discovered that APS, SRP, TEP, Citizens Utilities and Co-ops had similarities for this specific process. The following table identifies the high level common steps that the aforementioned Utilities currently require for a customer switch to Direct Access from Standard Offer when a meter exchange is involved.

Step	Process Description
1	A Direct Access Service Request (DASR) is received by the UDC from the ESP
2	The UDC sends information about the existing meter to the ESP and the MSP
3	The MSP sends information regarding the pending exchange date to the UDC
4	After the meter is exchanged, the MSP sends information regarding the newly installed meter to the UDC

Although each Utility has different timing requirements, data elements and business rules for each of the above steps, they each utilize a hardcopy form to exchange meter information for steps 2-4. Standardizing the data elements and forms used in steps 2-4 so providers would have the same requirements when operating in multiple service territories was the first development stage. The subsequent stages would be to look at timing requirements and business rules associated with each step.

The Utilities met on numerous occasions, independent of the subcommittee meetings, in an effort to develop a proposal to standardize steps 2-4. Currently, each Utility has different names for their forms used for steps 2-4. It was agreed to follow the California & CUBR models for the names of the proposed AZ forms. They are as follows:

Step	Form Name	Process Description
1		A Direct Access Service Request (DASR) is received by the UDC from the ESP
2	**EMI** = Existing Meter Information **EPA** = Equipment Purchase Authorization	The UDC sends information about the existing meter to the ESP and the MSP
3	**MDCR** = Meter and Data Communication Request	The MSP sends information regarding the pending exchange date to the UDC
4	**MIRN** = Meter Installation/Re-moval Notification	After the meter is exchanged, the MSP sends information regarding the newly installed meter to the UDC

Data Element Requirements (Best Practice # 1)

Each of the forms mentioned in the previous section has different data element requirements specific to its use. The data element requirements that the utilities are currently requiring were documented and compared to each other in an effort to standardize between participating Utilities. The comparison led to the Proposed Data Elements for process #1 for AZ. The final step was to compare the Proposed Data Elements for AZ to the National Standards, UIG and CUBR documents (Appendix M-4). After comparing our work to the National Standards, the final proposed version of the AZ Data Element Requirements was agreed upon by the subcommittee (Appendix M-5). ***Note:*** *The standardization of the data*

*elements is a business process agreed upon between the Utilities and the Providers and does **NOT** require Commission action.*

Meter Activity Forms (Best Practice #1)

After the data elements were identified, the working group developed the actual hardcopy EMI, MDCR & MIRN forms that would be used as standardized tools to exchange meter information between the UDCs and the Providers. The proposed forms can be found in Appendix M-6. ***Note:*** *The standardization of the Meter Activity Forms is a business process agreed upon between the Utilities and the Providers and does **NOT** require Commission action.*

Business Rules (Best Practice #1)

In addition to the data elements required on the EMI, MDCR & MIRN, there are business rules associated with each process step. A document was developed to show the comparison of current Utility business rules for each step as well as a comparison against a National Standard (Appendix M-7). From this, a comparison document was developed to identify the business rules that could be standardized. This document indicates whether a rule change is required, clarification of Staff's interpretation is needed, UDC Tariff change is needed, if it is a business process between the Utilities and the Providers or if consensus was not reached. This document currently represents the status of the proposed AZ Best Practice for this process (Appendix M-8). A high-level flow for Process #1 can be seen in Appendix M-9.

Market Benefits

- Documentation of current business rule by UDC in AZ
- Identification of similarities and differences between UDCs
- Discussion of issues and consideration of proposals to address implementation issues
- Consistent forms and data elements
- More efficient transactions between competitive providers and UDCs

Implementation Plan

- Each Market Participant will need to identify when each process can be implemented within their organizations
- Waivers will need to be submitted by Utilities for those Best Practices within each process that require a rule change

- Letters written to the Utilities Divisions Director to request changes in operating procedures

Next Steps

- Develop short term method for transmitting data electronically in a flexible format (i.e. CSV, Excel) for the EPA, EMI, MDCR & MIRN forms
- Develop data element definition document (on-going for all Best Practices)
- Develop AZ Metering Handbook (on-going for all Best Practices)
- Begin work on other Processes and related sub-processes:
  - Customer returning to UDC Standard Offer from Direct Access
  - ESP to ESP switch requiring meter work
  - Disconnect requiring meter work
  - Routine meter test
  - Notification of meter maintenance
  - Cancel DASR
  - Update Active DASR requiring metering work
  - MSP/UDC UN-schedules installation
  - Notification of electrical system change and permit request
  - Meter installation and approval process
  - Meter installation and energizing of electrical panel
  - Late MIRN notifications for DASR related work
- Develop 650 Implementation Guide
- Begin looking at Meter Reading Issues and Processes
- Develop scenarios for exception reporting to be used for the Exception Reporting Subcommittee
- Change customer ownership while retaining DA status (seamless move)