THE TDU GROUP's RESPONSES TO QUESTIONS POSED IN SLIDE 4 OF THE SPP CAWG's SEPTEMBER 8, 2004 "TRANSMISSION EXPANSION COST ALLOCATION PROPOSAL" PRESENTATION

1. BASE-FUNDING ISSUES

Question 1(a): "What level of flexibility, if any, should transmission customers have in resource designations in the base plan?"

TDU Response: Truly competitive markets will not develop in the SPP region if the ability of customers to designate network resources is significantly restricted. Customers should have maximum flexibility in designating and changing network resources. Transmission, which is a relatively small component of the total cost of delivered power, should not be the determinative factor driving resource decisions.

However, several types of "limits" on a customer's right to change DNRs have been suggested, and in the spirit of compromise, the TDUs do not object to a reasonable capacity margin requirement (e.g., 125%).

The TDU Group is also willing to consider a term-based requirement for a designated Network Resource that would be a prerequisite for including in the Base Plan any network upgrades needed to integrate the resource. Our view is that a three-year term is reasonable. In today's market, wholesale suppliers and customers are reluctant to commit for contract terms longer than three to five years. To require a commitment of longer than three years could result in a situation where transmission service requirements significantly alter the way that the wholesale market operates.

In addition, we believe that a capacity limit or term requirement should not preclude a customer with a shorter term commitment from seeking to have its new Network Resource included in the Base Plan. Such determinations could be made by SPP on a case-by-case basis. For example, a new power plant might push a customer's reserve margin above 25% in its first year of service, and the customer would be free to request that a needed upgrade be included in the Base Plan regardless.

Question 1(b): "What percentage of upgrade costs (X%) to be allocated to region-wide rate?"

TDU Response: We continue to believe that a single regional rate is a desirable "end state," and that achieving that end state would be promoted by allocating 100% of the cost of base-funded new facilities to the SPP region-wide rate. This approach recognizes that, over time, most upgrades to the integrated network will provide benefits that serve the region as a whole, including the creation of a transmission infrastructure that is sufficiently robust to maintain regional reliability and support competitive markets, and that all load serving entities will generally cause the same levels of upgrades.

To the extent, however, that X is not chosen to be 100%, we believe X should be set up front, and not be determined on a case-by-case basis. A fixed percentage provides the necessary certainty and simplicity that will provide an incentive for investors to finance transmission and expand the system infrastructure. A fixed percentage will also allow SPP to avoid analytical subjectivity and controversy and the need to periodically review the impacts. Over the long term, the cost allocations and the "benefits" of projects will equalize, so we see little need to analyze individual projects.

As to what the number should be, we are open to adopting a specific number, but we are not prepared to recommend something at this time. We are not sure there is sufficient understanding of the analyses performed thus far to rely on these as a basis for setting a fixed percentage.

Question 1(c): "How should the remaining portion of the costs be allocated among the zones?"

TDU Response: We continue to support a regional roll-in of base-funded facilities costs. In further support of our position, we note that the data that have been presented which purport to show the regional distribution of power flows, and the extent to which particular facilities support zonal versus regional flows, are highly scenario-dependent and subject to interpretation. Moreover, in order to achieve a correct treatment of costs over time, it would be necessary to re-perform such studies periodically (e.g., annually), to determine whether facilities previously thought to serve only a zonal function now provide benefits that are more regional in nature. To the extent such costs are subject to reallocation (between zonal and region-wide rates) based on the change in use, the resulting uncertainty is likely to impede customer support and investor confidence needed for the funding of needed infrastructure improvements. Rather than simply locking in an allocation based on the results yielded when the study is performed, the solution is to recognize that the changing use of facilities over time warrants a broad sharing of costs through the regional rate.

We need to be careful about using flows to allocate upgrade costs. We have a number of concerns about the development and implementation of flow-based mechanisms, which are detailed in an accompanying paper.

In addition, if we adopt an approach that allocates costs to zones based on flow impacts, it could have serious anti-competitive implications. Generation that is not nearby will be at a disadvantage because, instead of rolling in the costs of necessary upgrades, those upgrade costs would be assigned to the load serving entities in the zone. Local incumbent generation that does not require upgrades would have an edge. Using flows as a basis for pricing, whether it be a flow-based pricing system or an allocation of upgrade costs using flows, is simply a form of pancaking that tends to dampen competition.

Consider this example. Assume upgrades for network resources are included in the base plan, and a customer designates a power plant in an adjacent zone as a network resource. The system impact studies reveal that upgrades need to be made in the adjacent zone. A flow-based allocation approach would require the customer's zone to fund a significant portion (whatever is not regionalized) of the upgrades in the adjacent zone, which will suggest to the customer that local generation may be a better bargain. That is a less than desirable outcome in what is supposed to be a regional generation market.

Now, assume that the costs of the upgrades are assigned to the zone in which the facilities are located. The load serving entities in that zone will bear the costs of the upgrades for the customer in the adjacent zone. This obviously is not an ideal result either, but in our view this is preferable to using a flow-based method to allocate the costs back to the customer's zone. The load serving entities in the zone where the facility is located will see a benefit from the facility, and over time one would expect that there would be an equal impact across all zones in the region.

The zonal allocation problem is not an easy one, and it points out the problems associated with preserving the current zones. In the long run, the TDU group believes it is in the best interest of SPP to eliminate the zones. That should be the stakeholders' desired end state. We encourage the CAWG and the RSC not to look for compromise on this issue but to choose the best approach for SPP in the long run, which is to roll-in costs for new facilities as a means for transitioning to a regional postage stamp rate.

2. ECONOMIC UPGRADE ISSUES

Question 2(a): "Percentage of cost of economic upgrades to be allocated to region-wide rate (Y%)."

TDU Response: Since the TDU Group supports a regional rate design for new facilities, we would advocate that a large percentage of economic upgrade costs be allocated to the region-wide rate. The specific number would depend on the nature of the upgrade, the diversity and dispersion of the economic benefits, and the analysis of its contribution to region-wide transmission operations, but we have noted above that such analyses are scenario-driven and must be updated to reflect the changing use of particular upgrades over time. It has often been said in our meetings that "today's economic upgrade is tomorrow's reliability upgrade." We agree with that view, and we are also mindful that many economic upgrades produce diverse and widespread benefits to a number of load serving entities within the footprint. For these reasons, we seek to minimize the extent to which economic upgrade costs are charged through any rate element other than the region-wide rate.

Again recognizing that "today's economic upgrade is tomorrow's reliability upgrade," we would not want to see the "Y%" calculation become an impediment to expansion that may be needed to ensure future reliability. In general, we do not think "Y%" should be a function of the "strength of the economic benefits that are expected to result from the upgrade," at least where the upgrade will be used primarily to serve firm native or wholesale load within the SPP footprint. In such circumstances, the upgrade may provide substantial benefits to the region notwithstanding that it also offers significant benefits to a particular market participant. For example, an upgrade may provide benefits to a market participant currently subject to unusually high power supply costs by allowing it to access a more economic source of energy. However, the upgrades that make access to that resource possible also may provide important reliability benefits (present or future) to the regional network as a whole. In fact the newly integrated energy resource itself may support regional reliability by providing needed voltage support (e.g., to inject or absorb VARs) during times of system instability. Given these considerations, setting "Y%" at a low level will facilitate construction of needed transmission improvements, while also sending meaningful (yet reasonable) price signals about the implications of market participant resource decisions.

As to whether Y should be recalculated, we believe certainty and simplicity are necessary components of whatever policy is developed. Therefore, we suggest setting it initially at a low level, and then review in a few years to determine if it is reasonable and performing as anticipated.

<u>Question 2(b)</u>: "What rights does a Participant receive for voluntarily funding non-base funded projects?"

<u>TDU Response</u>: According to the handout dated 8/27/04, Participant Funding in SPP will comply with FERC's "or" pricing policy, and the portion of the upgrade cost that exceeds the base rate for firm transmission service will be defined as comprising Participant Funding. The handout identifies several rights that the funding party would receive in return, including: (i) firm transmission service; (ii) revenue credits from any PTP service sold because of the additional capacity created by the upgrade; (iii) the balance of funding not yet credited when the excess costs (above base charges) are rolled into rates; and (iv) inclusion of the service (including rollover rights) in future base plans.

We agree that the provision of rights to funding parties is a necessary component of the SPP Participant Funding Proposal, and we commend the CAWG for seeking to give effect to that view. However, we are concerned that limiting the crediting to additional PTP revenues is too limiting and uncertain, which means that the mechanism would not serve to provide useful incentives for the construction of needed transmission improvements. We propose instead that an allocation of revenues from network service also be used to provide credits against the "above base cost" charges associated with an economic upgrade. This will provide a greater measure of certainty to funding parties, which means that needed transmission improvements are more likely to be built.

The TDU Group favors adoption of the crediting policy analogous to Order No. 2003-A, for many of the reasons set forth in that order, including: (i) the obligation to provide upfront funding is a strong disincentive to inefficient siting decisions (P 627); (ii) factors that influence siting decisions are often beyond the control of market participants, while being within the control of state regulators (*id.*); and (iii) the Transmission System is a cohesive, integrated network that operates as a single piece of equipment, and, consequently, network facilities are not "sole use" facilities but facilities that benefit all transmission customers. For that reason, FERC "has reasoned that, even if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefiting all users due to the integrated nature of the grid"

(P 585). Consistent with the perception that "today's economic upgrade is tomorrow's reliability upgrade," crediting the cost of an upgrade over some time period returns the investment cost to the funding party (who may have been the primary beneficiary in the early years) while spreading the costs to the region as a whole as the upgrade's role within the network "transitions" from economic to reliability-related. Thus, the crediting mechanism not only eliminates the disincentives to construction that otherwise would exist, it also matches cost responsibility with the changing function of the upgrade over time.

We anticipate the argument that providing any credits will dilute the "price signals" that would prevent market participants from building new generation at locations that require substantial transmission improvements. As noted above, however, FERC observed in Order 2003-A that an interconnection customer must provide the upfront cost of interconnection facilities, and this obligation will provide parties planning to build new resources with "a strong incentive to make efficient siting decisions," even taking into account later credits for those costs. The same is true for a transmission customer's provision of the upfront cost of economic transmission upgrades: the obligation to raise the money to build the upgrade is a sufficient burden to ensure that customers will not seek upgrades that lack merit, simply because they will receive credits later. Moreover, since SPP itself must determine that the upgrade has merit in order to include it in the regional plan, SPP's independent review provides a further restraint on market participant actions with regard to economic upgrades.

COMMENTS ON ISSUES RAISED IN THE SPP CAWG's SEPTEMBER 8, 2004 "DETAILS TRANSMISSION EXPANSION COST ALLOCATION PROPOSAL" PRESENTATION

In Slide B.1, the CAWG asks whether economic upgrades should be mandatory or voluntary.

TDU Response: It would be difficult to implement a rule that all economic upgrades must be voluntary in some degree unless there are "clear and significant benefits" for the region. As we have argued, identifying the "benefits" of an upgrade is highly subjective, and the nature of the benefits will change over time. Therefore, application of this rule would require an evaluation of the nature and magnitude of a project's benefits over its entire life (as much as 50 years), without knowing how the system will change over such an extended period.

That being said, we agree with the principle enunciated in FERC's December 19, 2002 order in *PJM Interconnection, LLC*, Docket No. RT01-2-001, *et al*. (at P 24) that, in order to fully meet the planning and expansion functions set forth in Order No. 2000, an RTO's regional transmission plan must provide authority for the RTO to (i) require the necessary additions to its TOs' systems to ensure reliability, and (ii) identify transmission constraints that must be relieved to support competition and require new construction to remove those constraints. Unless SPP has such authority, competition-inhibiting constraints on the SPP network may persist for years, depriving consumers of one of the key categories of benefit from an up-to-date, robust and reliable regional transmission network.

In Slide A.2, the CAWG states: "[w]hen the costs of projects are assigned directly to those requesting a new network resource (current SPP practice), the requestor ends up paying for more transmission expansion than is needed and must pay for it as "and" pricing."

TDU Response: We disagree that it is the current SPP practice to directly assign the costs of projects to those requesting a new network resource. It is our understanding that SPP follows FERC precedent in allocating costs of facilities associated with new network resources. Nevertheless, we agree that direct assignment of such costs would result in the requestor having to pay for more transmission expansion than is needed, and for that reason, such costs should be base funded.

TDU GROUP'S CONCERNS WITH FLOW-BASED COST ALLOCATION METHODS

At least two different flow-based methods have been offered for consideration in connection with the ongoing discussion of transmission upgrade cost allocation methods in SPP. In the context of these discussions, a flow-based method might be applied for either or both of two purposes: (1) to determine portion of the costs of Base Plan Funded facilities that will be treated as regional in nature ("X%"); and (2) to determine the split among zones for that portion of the costs of BPF facilities that are determined not to be regional in nature (1-X%). In addition, a flow-based method might be adopted for the purpose of assigning cost responsibility among the claimed beneficiaries of economic upgrades that are not fully funded through voluntary participation (*i.e.*, mandatory upgrades).

Flow-based methods are not without their proper place in system planning, and even in helping decide certain narrow issues of transmission system cost responsibility.[1] However, the TDU Group has significant concerns about the application of flow-based methods for any of the purposes now being contemplated by the CAWG, and especially as a basis for allocating transmission upgrade costs among zones (and, potentially, among customers). Our concern about the use of flow-based methods can be summarized as follows:

1. <u>Complexity</u>

Flow-based analyses are inherently data intensive and complex, and will consume substantial SPP staff time and resources. Of necessity, these analyses require the modeling of the entire transmission network under a range of operating conditions. Information about facility ratings, transformer tap settings and line switching configurations, line capacitance and deployment of reactors, generation availability and dispatch, and the like all would need to be a part of the network model used to predict power flows and the effect that transmission upgrades would have on power flow patterns. The complexity of the analysis will be compounded if power flows are evaluated during more than just the annual peak hour (e.g., for each monthly peak hour, or during off-peak hours, to ascertain the impacts of an upgrade on power flows under a range of operating conditions).

2. <u>Subjectivity</u>

Power flow analyses are also inherently "scenario driven," which is to say that, apart from the complexity, the results are strongly affected by the assumptions made by planning personnel in developing and running the power flow model. As was repeatedly acknowledged during the CAWG conference call of September 14, considerable judgment is exercised in deciding among the various assumptions (any of which may be reasonable standing alone) that are used to structure the "base" and "change" cases used to analyze the impact of an upgrade on the network. Engineers with sufficiently

[1] Flow based analyses such as system power flow studies can be helpful in identifying unscheduled or unauthorized parallel flows that burden other interconnected systems and trigger a need for compensation to the burdened system.

familiarity with the model and the systems being studied must choose among these various individual assumptions, but often without being certain that the combination of these assumptions will yield reasonable results when the model is actually run. Furthermore, because of the subjective nature of the process, it is virtually "unauditable" by outside parties, even those having general familiarity with transmission planning and modeling procedures. To the extent that the selection of assumptions is left in the hands of non-independent parties (*e.g.,* transmission owners or other market participants), there is a strong potential for bias in the results.

Because the application of flow-based cost allocation approaches is so highly subjective in nature, and because the study results will have significant economic ramifications for market participants, there will almost certainly be frequent challenges and disputes over the results. Defending the studies and the study results will consume yet more of SPP's limited budget and staff resources. This is not a good use of SPP resources, especially where such disputes may also have the effect of discouraging needed transmission improvements in the region.

3. <u>Failure to Reflect Changes in System Conditions</u>

Because of the complexity of power flow studies, they are often quite costly to perform taking into account the need to assemble large amounts of data, as well as the computing time needed to run the model for a large integrated system with many network elements that must be reflected in the model. Given these factors, there is a predisposition to conduct the power flow study for only one or a very few hours during the year, and for a very limited number of contingency cases (cases that examine the impacts on the system of the unavailability of key network elements). However, a full understanding of the functions that an upgrade will provide in the network demands an examination of system flows under a range of conditions (peak, off-peak and shoulder loading), and a reasonable range of contingencies. Unless studies of this range are performed, the process of identifying the "benefits" of an upgrade will be incomplete.

Furthermore, the function that any network element performs within the integrated system will change over time as the topology of the network itself changes as a result of such factors as the addition (or retirement) of other transmission facilities, the addition (or retirement) of generation facilities, changes in the distribution of loads on the network, and changes in the direction and magnitude of parallel path flows. Changes over time in any or all of these factors will affect the function that a particular network upgrade serves as part of the integrated network. Therefore, in order to ensure that the function of a network element continues to be properly reflected for various purposes (including, as proposed by the CAWG, for cost allocation purposes), it will be necessary for transmission planners to re-run the system models on a regular basis and as other changes in system conditions may warrant. This will add to the cost of implementing any flow-based approach, as well as the extent to which these activities will consume the time and attention of SPP personnel.

4. <u>Failure to Reflect the Actual Distribution of Benefits</u>

During the September 14 CAWG conference call, it emerged that cost allocation proposals that begin with an evaluation of the distribution of benefits suffer from a fatally flawed assumption: that the benefits produced by any upgrade (e.g., in the form of reduced production costs) necessarily will be passed through to the ratepayers who will bear ultimate cost responsibility for the upgrade itself. As was pointed out during the discussion, however, there is simply no basis for that assumption. There are a number of reasons why the benefits produced by an upgrade may not, in actual practice, be received by the ratepayers who would be assigned the costs of the upgrade. For example, LSEs within the zone deemed to benefit from an upgrade may be served under long-term bilateral contracts in which the pricing of service is not affected by changes in regional or zonal production costs. Other customers may be located in jurisdictions that are subject to regulatory rate freezes, such that production cost savings experienced by the franchised service providers are not required to be passed through to customers.

Proper application of a "beneficiary pays" approach requires confirmation that the benefits of an upgrade actually are conveyed to the customers that will be assigned the costs of an upgrade. If there is a "disconnect" between the receipt of benefits and the assignment of costs, then the "beneficiary pays" concept will be subverted, and pricing will be essentially arbitrary in nature. We have doubts that such an approach would withstand close scrutiny under conventional, widely accepted cost-causation principles of electric utility ratemaking.

5. Possible Application to Sub-Zonal Allocations

Finally, we are concerned that, where flow-based methods are used to allocate costs between and among zones, there may be an effort or desire to extend those same approaches to sub-zonal or customer-specific cost allocations for network upgrades. In part, this concern arises from our view that flow-based methods, though often deeply flawed, give the appearance of being highly systematic, unbiased and accurate. Based on that perception, regulators may believe that flow-based approaches are equally suitable for allocating costs on a more granular level than simply between and among zones.

As we have explained above, flow-based methods are subjective, scenario driven and highly judgmental. Their use for sub-zonal cost allocation purposes would present the same concerns as are described above, but magnified by the much greater impact that sub-zonal allocations can have on individual wholesale customers. The use of such flawed approaches for allocating upgrade costs is inherently problematic; but the use of such methods for sub-zonal or customer-specific cost allocation purposes would be highly anticompetitive and subject to abuse. For that reason, adoption of flow-based methods for allocating upgrade-related costs is best avoided entirely, lest SPP take the first step onto a slippery slope that could have disastrous results for customers.