DESCRIPTIONS OF COMPETITIVE MARKET MODELS

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in Evaluating the Effect of Alternative Market Models
on the Achievement of Certain Public Policy Objectives

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This paper is intended to help participants in the CPUC's Working Group understand the various market structure models being considered in the CPUC's electric restructuring proceeding. A key task of the Working Group is to understand how the various models deal with the public policy issues listed in the CPUC's December 7, 1994 Order. The model descriptions are meant to be general and somewhat simplified, focusing primarily on those features of each model that appear to be most relevant to the Working Group's tasks.

As required by the CPUC's Order, three generic models are described here, but the descriptions do not quite match the three models listed in the CPUC Order on page 9. The reason is that the advocates of the models described in this paper may not always agree with the way the Order characterizes their models. To avoid this problem and make the Working Group's efforts more relevant, this paper attempts to describe the models in ways that the advocates would do so for their own models, but to use generic terms as much as possible so that the similarities and differences between the models can be more clearly seen and understood.

Readers are cautioned to remember that each of the principal model advocates are continuing to develop their models (and examine competing models) and to make refinements. Advocates of each model may wish to add further details, clarifications, or corrections to reflect their models more accurately and to assist the Group.

Model A: A Phase-in of Direct Access with a Limited Independent System Operator – Utility proponent: PG&E

Under this model, retail customers would be allowed direct access to alternative generation suppliers under a staged process or "phase-in." The phase-in would begin with the largest industrial customers and gradually bring in smaller customers over a period of several years. The CPUC's "*Blue Book*" would stretch this phase-in over a period of six years, beginning in 1996. Under PG&E's proposal this phase-in would also begin in 1996 with the largest industrial customers and occur over a 12-year period, eventually including residential customers by 2008.

Those customers eligible for direct access to competing generation services would be free to choose between continuing to purchase electricity supplies from the local franchise utility (e.g., PG&E) or to purchase that power from competing suppliers other than the utility. Regardless of the supplier chosen, the power would be transmitted and distributed over the existing utility grid and distribution system. In that physical sense, all customers, direct access or otherwise, would continue to be connected to the local utility. However, billing for electricity services would be separated and come partly from the utility (e.g., for distribution services) and partly from competing suppliers (for the electricity supplied). The utility itself would be free to compete to be the electricity supplier for direct access customers.

The "duty to serve" under Model A: Under PG&E's direct access proposal, the utility would use its entire resource portfolio -- the plants it owns and the power it has under various contracts with other suppliers -- to serve both direct access customers it retained in the competition and those customers not yet eligible for direct access. However, the utility's "obligation to serve" would not be the same for all customer types. For direct access customers supplied by other suppliers, PG&E's obligation would be limited to the responsibility to connect the customer to the distribution system and to allow those customers access to the competitive generation market, including access over PG&E-owned transmission and distribution lines to competing suppliers. For remaining customers -- "utility service customers" -- PG&E's obligation would include the traditional obligation to serve. For these latter customers, PG&E would remain the exclusive provider of electricity supplies and related services. Given that obligation, this paper assumes that, for utility service customers, PG&E would be the entity with the responsibility for acquiring resources and maintaining an economic, reliable, (and diverse) resource mix, as well as the responsibility for operating that resource mix in a way that minimized costs to those customers.

[The Working Group may wish to consider the implications for resource procurement, DSM and diversity polices flowing from this continuing obligation to serve some customers during the phase-in period.]

The competitive generation market. Under Model A, competing generation suppliers, which might include the utility itself, would compete with each other to meet the electricity supply needs of direct access customers. Under a phase-in, this market would therefore include a few customers at first, and gradually more customers over time. The size of the direct access market would thus grow over time at a rate tied to the phase-in schedule.

Advocates of this approach expect that direct access customers, either individually or in groups, would shop for the most competitive electricity supplies and enter into "bilateral contracts" with suppliers. Brokers, supply coordinators, and other market intermediaries would attempt to match customers and suppliers at agreed-upon prices and terms. A supply coordinator (which might be a generator, a customer, or an intermediary) would then be responsible for coordinating with the overall system operator to ensure that the generators' supplies and the customers' loads could be scheduled safely and reliably on the electricity grid and distribution system.

Supply coordinators could have a range of interactions with the system operator. At a minimum, the coordinator would provide the suppliers' scheduling information (planned output amounts and times) and the customers' load information to the system operator. If there were no deviations from those schedules and no congestion on the transmission grid to inhibit the transaction, little further interaction with the system operator would be necessary.

If there were deviations, such as might occur when the customers took more or less power than anticipated by the bilateral contract, or the generator produced more or less than specified by the contract, then one of two things might happen. First, the supply coordinator might itself attempt to rebalance generation and loads between the suppliers and the customers, possibly arranging through further bilateral contracts with other generators or customers to increase (decrease) generation or loads. Potentially, there could be market places (or "hubs"), futures markets, and other means through which coordinators could buy or sell supplies, to assist in this rebalancing. Information about these rebalancing efforts would then be provided to the system operator, and payments for these adjustments would flow strictly between the various bilateral parties.

Alternatively, for small (or short-term) imbalances the supply coordinator could rely on the system operator to rebalance generation and loads. In that case, the system operator would presumably have at least some amount of flexible generating capacity (or flexible customer loads) under its control which could be called upon to either increase or decrease generation (or loads) to rebalance the system. If this approach were used, the system operator would then have to charge the bilateral parties for any imbalances made up by the system operator. For example, if the system operator provided additional generation (e.g., to cover higher than expected demands or less than expected generation by the bilateral parties), it would need to charge the bilateral parties for any additional generation provided and pay the backup suppliers for the backup generation provided.[1]

Limits on the system operator's functions. In the PG&E proposal, the functions of the system operator would be purposely limited to performing only those grid control and

[1] The process, common to all models, of accounting for and paying or collecting these payments and charges is sometimes referred to as the "settlement" mechanism. In the PG&E proposal there would be a "settlement agent" to perform this function.

rebalancing functions necessary to maintain system reliability and stability. The degree to which bilateral parties would rely on the system operator for rebalancing -- i.e., making up for imbalances caused by deviations between the supply and demand anticipated by the bilateral contract and the amounts actually generated and consumed -- would be correspondingly limited. Suppliers and customers, and their supply coordinators, would be expected to make all reasonable efforts to maintain their own balances, and not to impose large imbalances on the remainder of the system or the system operator. The bilateral parties would assume some of the risks of failing to achieve these balances. Under this approach, PG&E expects that the remaining balancing function that would have to be provided by the system operator would require only about 400 megawatts, at least for the initial years of direct access.

The role of "economic dispatch." In today's electricity system, each utility performs "economic dispatch," which in general means the process of selecting the least-cost mix of available resources to meet total loads at any given moment and then calling upon those resources in the correct "merit order" to achieve the least cost operation. In the PG&E approach, PG&E would continue to perform the economic dispatch function with respect to all its own plants, which would be supplying both its direct access and utility service customers. Presumably, supply coordinators for non-utility plants associated with bilateral contracts with other direct access customers would conduct their own economic dispatch, calling upon the least expensive plants available *to them* at any given moment to meet the contract requirements. Thus, there could be multiple economic dispatches occurring, but there would be no central entity pursuing an overall economic dispatch for all plants available to meet the needs of all customers throughout the system.

PG&E's proposal contemplates that the overall system operator would be an independent entity; that is, it would be independent of PG&E and any other market participant.[2] As noted above, the functions of the independent system operator (ISO) would be limited, and the amount of flexible generation made available to the ISO for maintaining system balance and reliability would be purposely limited, to allow and encourage direct access customers and their bilateral contract suppliers to provide their own generation/load balancing. Under this approach, therefore, the ISO would not provide a central economic dispatch function. This feature of the PG&E model distinguishes it from the "pool-based" model described later in this paper.

Pricing for electricity and related services. The phase-in of direct access could result in two different pricing schemes, one for direct access customers, the other for utility service customers. Direct access customers would presumably receive a bill for distribution and related services from the local monopoly utility and receive a separate bill -- for the amount of electricity consumed -- from the competitive supplier with whom the customer had a bilateral contract.[3] In simple terms, billing for the "commodity" versus the "delivery" would be separated or "unbundled." Billing arrangements for the unbundled commodity would be unregulated and determined by the contracting parties. The bill from the utility for "delivery"

[2] PG&E expects the independent status of the system operator would be achieved by about 1997, about one year later than PG&E's proposed starting date for direct access for the first group of large industrial customers.

[3] Physically, these "separate" bills could be united, as now occurs for local and long-distance phone service.

and related services would be based on rates regulated by the CPUC. Finally, the costs of ancillary services provided by the ISO would be billed either separately or within the utilities' bill for distribution services.

Under the PG&E proposal, the bill for utility service customers -- those ineligible for direct access (and perhaps those who are eligible but who choose to remain with the utility) -- could remain completely "bundled," combining both the commodity and the delivery charges in a single rate. However, there is no inherent reason why various aspects of the total utility service could not be unbundled and priced separately, even for these customers. Thus, unbundled prices for all customers, which might facilitate DSM and customer choice options other than direct access to generation, could be an option in the PG&E approach without undermining its basic concepts.

Resource diversity under Model A. The Model A approach would allow a diversity of generation in at least two different ways. First, the utility itself could acquire diverse resources on its own through competitive auctions or separate contracts and purchases. Since the utility would have the obligation to serve those customers still ineligible for direct access, it would also have the duty to plan the resource mix. State tax and regulatory policies could be used to encourage or subsidize any "preferred" resources in the utility's resource mix.[4]

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[4] These options are merely possible under this model. They are not necessarily part of the PG&E proposal.

Second, supply coordinators (or the utility itself) could offer power supplies from one or more portfolios of diverse resources to those direct access customers who wanted such a portfolio. For example, a "renewable portfolio" could include a mix of both low-cost and higher-cost plants to allow the portfolio as a whole to be reasonably competitive. Or, a higher-cost portfolio could be offered to those customers willing to pay a premium for "preferred" resources. In another variation, the attractiveness of a "biomass portfolio" could be assisted by supplemental payments (such as tipping fees and residue collection fees) derived from those entities who received the "externality benefits" of biomass operations. The success of these portfolios in the direct access market would depend on their competitiveness and the willingness of customers to pay any premium.

Model B: Creation of a Voluntary Pool to Allow Direct Access for All Customers.

Principal utility proponents: SDG&E, SCE

This model shares many of the characteristics of the Model A direct access approach described above. It allows customers direct access to a competitive generation market and allows those customers to engage in bilateral contracts for electricity supplies with the suppliers of their choice. It retains the local monopoly utility as the provider of distribution services, and hence it retains the physical "wires" connection and a billing relationship between customers and their local utility. Like the Model A approach, it features an independent system operator (ISO). And like the Model A approach, it assumes that not all customers would be ready for direct access all at once.

There are also differences. First, the "phase-in" of customers to direct access is treated differently. In Model A, the length of the phase-in and the order in which customer categories become eligible for direct access would be fixed in an agreement enforced by the regulators and the utility. In Model B, there is a similar recognition that not all customers would be ready or able to implement bilateral contracts all at once. However, customers and their suppliers would be allowed to proceed when ready, thus controlling the timing of their own "phase-in" as bilateral deals were struck and metering equipment was installed. A fixed phase-in schedule would not be set or enforced; all customers and customer categories would be "eligible" for direct access from the start.

Second, the "start" of Model B could be later than Model A. PG&E proposes to begin its approach in 1996, with the transfer of system operation functions to an ISO to take place sometime in 1997. Model B requires the creation of an mechanism called "the pool," as described below. SCE and SDG&E propose to have the pool-based market functioning by 1998. Every model's proposed schedule, however, is subject to numerous uncertainties about transition requirements and state and federal regulatory approvals.

Third, proponents of this approach are seeking to include several geographically close utilities (including municipals) in a common market. The utilities would agree to participate in a common "pool" or pool-based economic dispatch offered by a common ISO. The multi-system ISO would then dispatch generation in a least-cost manner to meet the combined needs of all participating utilities and their customers. Other utilities throughout the region would be encouraged to join the "pool" on equal terms.

Fourth, Model B does not attempt to limit the degree to which the independent system operator (ISO) may offer an economic dispatch function nor limit the quantity of generation or the number of market participants (generators or customers) who can use that dispatch service. The ISO would provide, *on a voluntary basis*, an economic dispatch service, based on dispatching any flexible plants offered to the ISO. Any generator, whether it had a bilateral contract or not, could choose to participate in the economic dispatch, but would not be required to do so. Similarly, any customer with flexible loads, whether it had a bilateral contract or not, could elect to participate in the economic dispatch. The ISO would then dispatch flexible plants (or loads) on a least-cost, merit order basis to meet all remaining system loads not being met by scheduled plants (such as those plants associated with bilateral contracts who chose not to participate in the economic dispatch). The ISO would use the flexible plants and the dispatch service to perform the system balancing function.

To determine the "merit order" for its economic dispatch, the ISO would receive price, quantity, and availability "bids" from those generators choosing to participate in the dispatch. The ISO would examine the bids and determine the most economic (least cost) order in which to bring on more generation or decrease generation to maintain system balance. Customers with flexible loads could choose to be treated the same way. In operating the system, the ISO would first schedule all "non-flexible" generation associated with direct access contracts, thus allowing those transactions to be implemented, and then use the dispatch merit order of the bidding plants to meet the remainder of customer loads. *The mechanism for accepting bids, establishing the order for economic dispatch, and settling the payments and charges for generation provided by suppliers and purchased by customers is collectively referred to as "the pool."*

The "duty to serve" under Model B. Under a pool-based approach, the local monopoly utility would probably not retain the traditional obligation to serve. As in Model A, the local utility would have a responsibility to connect all customers to the distribution system and to allow those customers access to the competitive generation market, including access over utility-owned transmission and distribution lines to competing suppliers *plus access to the ISO's economic dispatch services*. However, the duty to provide electricity supplies would shift from the local utility and be divided between the "the pool" and the competitive market. That is, the duty to ensure that sufficient generating plants were economically dispatched to meet all customer loads would become the responsibility of the independent system operator, relying on the pool's merit order of flexible plants and the market prices bid in by those plants and customers who chose to participate in the economic dispatch. The responsibility for ensuring that there were, in fact, sufficient generating plants available to meet all loads reliably would rest with the competitive market, relying on price signals provided by that market. Under this approach, therefore, the current utilities would not necessarily be responsible for acquiring resources or maintaining an economic (and diverse) resource mix for electricity customers. Those responsibilities would shift to the market participants, including the customers themselves. *[The Working Group may wish to consider the implications for resource acquisition and attainment of DSM and diversity policies flowing from this shift in responsibilities.]*

The competitive generation market. Under this model, competing generation suppliers, which might include the utility itself, would compete with each other to meet the electricity needs of the entire multi-area system, either through wholesale transactions via the "pool," retail transactions with retail customers, or both. All customers would be "eligible" for direct access. There would be at least three different methods by which generators could choose to compete:

<u>Option 1:</u> First, generators could choose to participate in the system operator's economic dispatch and could bid a price into the pool for any part of their generation output. Using the pool mechanism, the system operator would select and dispatch those generators that bid the lowest prices for any given period. Any competitively-priced generator, whether utility or

independently-owned, would be assured of participating in the dispatch and receiving the market clearing price for its generation.

Option 2: Second, generators could enter into bilateral contracts with any customers and also choose to participate in the system operator's economic dispatch. The power offered for economic dispatch could be either the same power linked to the bilateral contract or excess power that the generator could produce beyond the needs of the bilateral contract (or power unused when the bilateral customer lowered its demand). The generators could operate to meet the needs of their bilateral customers, but the ISO might also dispatch a generator up or down depending on the generator's price bid and the system operator's marginal cost of generation. For example, when the ISO's marginal cost was below the generator's bid price (presumably its operating costs) the generator's output would be curtailed, and it would rely on the ISO to meet its bilateral contract requirements at a price lower than the generator's operating costs. In effect, the generator would be "buying" power from lower-cost generators participating in the ISO's economic dispatch to meet its bilateral contract obligations.

Option 3: Third, generators could choose to enter into bilateral contracts of the type described in Model A, while choosing not to participate in the system operator's economic dispatch. *Essentially, this option is exactly the same "bilateral approach" described in Model A.* As in Model A, the generator would provide the ISO with the generator's scheduling information, but no bid price information, and update the system operator as necessary regarding any changes resulting from its own efforts to balance its generation against the loads of its bilateral customers.

Limits on the system operator's functions. Under any of Model B's three options, the ISO would provide system balancing functions for all generation and loads, *as needed*, but without any assumed limitation[5] as to the amount of rebalancing that the market participants might request or need. After performing these services, the ISO's "pool" mechanism would settle with all participants, charging customers for their consumption and paying generators for generation supplied, with all payments and charges occurring at the market clearing price. In effect, the payments and charges would "pass through" the pool and match or offset each other. Of course, those bilateral generators and customers who functioned under Option 3, and who maintained their own balancing function without reliance on the ISO for rebalancing, would settle their payments and charges between themselves.

The role of "economic dispatch." In the pool-based model, the ISO would offer an economic dispatch service to all generators and customers who chose to use it. Participation would be entirely voluntary. The dispatch function would also be centralized, although generators utilizing Option 3 described above need not participate and could participate in their own dispatch. Note, however, that even these bilateral parties would be free to fall back on the pool-based dispatch to meet changes in their generation and consumption not anticipated by the contracts. While these parties would be free to use other bilateral fall-back measures that might

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[5] Recall that in the Model A or PG&E approach, the proponents would limit the generation available to the ISO for system balancing to 400 megawatts and encourage bilateral participants to achieve their own generation/load balances without resort to the ISO.

be more economic (and bear the risks of those measures failing), there would be no reason to preclude or limit their ability to use the ISO's balancing functions to back-stop their bilateral transactions. With these choices, the bilateral parties could decide for themselves whether or not this option enhanced the reliability or economic efficiency of those transactions.

Pricing for electricity and related services. As in Model A, pricing under Model B would require the unbundling of the "commodity" price from the "delivery" price. The "delivery" price would be billed by the local utility and shown separately on the customer's bill. Additional charges, such as any transition charge (the "CTC"), ISO charges for ancillary services, and charges/fees for public policy programs, could also be listed separately.

Under Model B, the "commodity" price could depend on which competitive option the customers and generators used. Under Option 1, the price would be established by the pool-based economic dispatch, with the pool's commodity or "spot" price representing the price bid by the last generator (i.e., the lowest-cost generator left in the merit order of dispatch) selected by the ISO during any given period. In effect, the pool's "spot price" would represent the short-run "wholesale price" of electricity at each location on the grid. Proponents of Model B anticipate that this stream of wholesale prices could be simply passed through the utilities to retail customers, in effect giving all customers direct access to the wholesale price. Customers could choose either to have this stream of prices aggregated and shown as a total commodity price or itemized by each time period. In the latter case, customers would then have real-time, time-of-use pricing, based on the actual cost of generating electricity at each hour or half-hour of the day. Using this real-time price information, customers would be free to pursue any number of DSM and load management options offered to them by DSM marketers or by the (distribution) utilities themselves.

Under Option 2, customers could also receive a bill for the stream of pool spot prices, allowing real-time, time-of-use pricing to occur. However, the final commodity price would be set by the terms of the bilateral contract between suppliers and customers. Proponents anticipate these prices would tend to vary around the Pool's spot price and could be used to hedge against the variability of that spot price. Bilateral contract prices might also reflect the contracting parties' value for longer-term certainty or any other factors they deemed important. The difference between the payments and charges at the pool's spot prices and the contract prices would be settled between the parties through "contracts for differences."

Under Option 3, the commodity price would also be set by the terms of each bilateral contract, but with no relationship to the pool's wholesale spot prices. Payments and charges would flow strictly between the contracting parties.

Resource diversity under Model B. The pool-based Model B approach would allow a diversity of generation resources in several ways. First, any type of generator, such as a renewable resource, would be free to participate in the pool-based economic dispatch offered by the ISO (Option 1, above). Those resources that were competitively priced would presumably participate in the dispatch service and receive the market clearing price for their generation.

Similarly, such resources could enter into bilateral contracts with specific customers and also participate in the ISO's economic dispatch (Option 2, above).

Second, just as in Model A and Model B's Option 3, independent supply coordinators (or "portfolio managers"), including the utility itself, could offer power from a portfolio of diverse resources to those direct access customers who wanted such a portfolio. The portfolio could include a mix of both low-cost and higher-cost plants to allow the entire portfolio to be reasonably competitive. Or, a higher cost mix of resources could be offered to those customers willing to pay a premium. Thus, all of the direct access diversity options available under Model A would be available under Model B.

In Model B, direct access options could be accomplished whether or not the portfolio (or individual plants within it) chose to be part of the pool-based economic dispatch. In either case, State/regulatory policies could be used to encourage or facilitate the success of preferred technologies. Within the Model B framework, tax credits or other direct subsidies could facilitate any resource's participation in the pool-based economic dispatch or, as in Model A, reduce the premium for a diverse resource portfolio to make it more attractive to direct access customers.

Model C: Pool-based economic dispatch with no (or delayed) direct access for retail customers. Proponents: possibly some municipals.

The concept underlying Model C is to use the pool-based economic dispatch offered by the ISO in Model B (Option 1) while precluding retail customers from engaging in direct access bilateral trades (Options 2 and 3). As in Model B, proponents of this approach assume that several geographically close utilities would agree to participate in a common, pool-based economic dispatch carried out by a common ISO. That is, a multi-system operator would dispatch generation in the least-cost manner for generators meeting the needs of all participating utilities and their customers. Unlike Model B, however, Model C would purposely limit the ability of retail customers to obtain direct access to the competitive generation market.

In effect, Model C provides a means by which utilities who wish to participate in the common market afforded by the Model B approach, but which are not yet prepared to allow direct access, may still join with utilities who are prepared for direct access and receive the benefits of the open wholesale market created by the pool-based economic dispatch. Model B could be created by several utilities, some of whom (e.g., SCE and SDG&E) would provide their customers all three of the Options described in Model B and some of whom (e.g., one or more municipals) would provide their customers only Option 1. Model B thus includes Model C (just at it includes model A).

Proponents of Model C may believe that most, if not all, of the price benefits of generation competition would be obtained at the "wholesale" level through the pool-based economic dispatch mechanism; the resulting "wholesale" prices could then be passed directly through to retail customers. Proponents may also assume that allowing each local franchise utility to remain the exclusive provider of electricity to retail customers limits each utility's exposure to stranded costs, since there is little or no risk that the utility will "lose" customers to competing generation suppliers. (To a lesser degree, this risk-limiting effect is present in the phase-in of direct access under the PG&E proposal.)

The "duty to serve" under Model C. The precise status of the duty to serve in this model is somewhat ambiguous; it would depend on the intentions of the proponents. Under one view, this Model resembles Model B: the duty to ensure efficient operation of available resources to meet all loads shifts from the local franchise utility to the pool-based economic dispatch function of the ISO; the duty to ensure there are sufficient resources available to reliably meet all loads shifts from the utility to the market participants. However, it is conceivable that participating utilities, particularly those with municipal franchises, would continue to assume a utility duty to meet all franchise customer loads reliably and efficiently and to pursue diversity policies. Under this view, the duty to serve would resemble PG&E's obligations to utility service customers, as described under Model A. *Working Group participants may wish to carefully distinguish these different utility perceptions when examining how Model C might affect whether the utility continues to have responsibilities relating to resource acquisition, DSM, and pursuit of resource diversity.*

The competitive generation market. Like Model B, competing generation suppliers, including the utility itself, would compete with each other to meet the electricity needs of the entire, multi-franchise system. However, participation would be limited to taking part in the pool-based economic dispatch conducted by the ISO. This is essentially a "wholesale market." There would be no ability for generators to participate in a direct access "retail market" as described in Model A or Model B, Options 2 and 3.

Model C assumes that there would be some mechanism to prevent retail customers from engaging in bilateral contracts with competing suppliers. Such mechanisms would be necessary because in a pool-based system in which wholesale prices were passed through to retail customers, there would no way to prevent retail customers from pursuing bilateral "contracts for differences" that keyed off the pool-based wholesale price. Generators could participate in the pool-based economic dispatch and, without the knowledge of the utility or the ISO, sign bilateral contracts with retail customers, allowing both parties to hedge the uncertainty and variability of the pool's spot market prices. Contract charges and payments would flow between the bilateral parties, again without the knowledge of the utility or the ISO. Assuming advocates of Model C regard these transactions as inappropriate, some mechanism would be necessary to foreclose this simple, straightforward economic activity, or else Model C would quickly evolve a Model B, Option 2.

There are at least two such mechanisms possible. First, the utility could refrain from unbundling its services and prices, making it difficult for customers to compare the "commodity" price of electricity between the utility rates and competing suppliers' prices. Without an accurate means to make this comparison, bilateral transactions might be difficult to negotiate and risky to pursue. However, this method precludes the utility from providing the customer with the stream of pool-based spot prices, preventing real-time, time-of-use pricing to facilitate DSM. Second, local franchise agreements could retain the utilities' exclusive monopoly over metering services and exclusive access to metering information at the customer level.[6] Without access to metering information, competing suppliers would find it difficult to implement bilateral contracts. Note, however, that limiting access to such information might also inhibit an active market for DSM services from providers other than the local utility.

Limits on the system operator's functions. Like Model B, Model C would place no limits on the ISO's ability to offer an economic dispatch function. All generators (and flexible customers) could participate. After performing this function, the ISO's pool/settlement mechanism would settle with all generators and participating utilities (customers), charging customers for their consumption and paying generators for generation supplied, with all payments and charges occurring at the market clearing price and offsetting each other.

The role of "economic dispatch." This feature of Model C is identical to Model B, without the direct access variations.

[6] In the United Kingdom, the most recent phase of direct access has encountered serious problems and delays because there were insufficient meters installed to accommodate all current phase customers' desires to implement bilateral contracts. The U.K. left the local distribution companies with the exclusive rights to install meters.

Resource diversity under Model C. The pool-based Model C would allow a diversity of generation resources to occur in at least two different ways. First, any generator could participate in the pool-based economic dispatch, provided it were competitively priced. Second, participating utilities could, on their own, acquire their own diverse portfolios. To the extent that individual resources or portfolios were uncompetitive within the pool, the utility could still bid them into the pool at a "zero price," thus assuring their participation in the dispatch order. The utility could then pass the "uneconomic costs" of such resources through to its own customers, with the added costs either rolled into the energy rate or separately specified as a "diversity" fee on the customers' bills. This would allow a utility, e.g., SMUD, to pursue diverse resources within a pool framework as long as its customers agreed to pay any resulting above-market premium associated with the diverse portfolio.

The Working Group may wish to examine all diversity options that rely on direct or indirect subsidies for their effect on the efficiency of the wholesale competitive market. In effect, such options allow subsidized plants to bid into a competitive market, potentially displacing more efficient (lower-cost) plants from the dispatch order.