2. Central Station Policy

2.1 Summary of Recommendations

The following Staff recommendations pertain to central station resource acquisition and related Michigan retail electric customer choice market issues:

1. Modify Commission policy to assure cost based rates for efficient functioning of the Michigan market.
2. Modify Commission policy to set a mandatory planning reserve standard for all load serving entities.
3. Provide Commission with authority to establish integrated resource plan standards, issue a certificate of need for new utility generating plant, and require incumbent utilities to competitively bid the EPC costs of a new generating unit.
4. Require a utility proposing to build a new generating unit to file a financing plan for the unit’s construction costs. Modify Commission policy so the Commission, at its discretion, could extend its policy of permitting CWIP in ratebase for pollution control investment to some or all of the remaining plant investment.
5. Provide authority to assure that customers who cause plant construction to be undertaken will contribute to the recovery of the plant’s cost. Customers who take service from an alternative electric supplier would be required to notify their incumbent utility two years prior to returning to regulated rates.

2.2 Introduction

Central Station resources are conventional electric generation plants, including baseload, intermediate, and peaking units. Conventional hydropower, including dams and the Ludington pumped storage plant owned by Consumers Energy and DTE, are also included in this category. Strong consensus exists among Plan participants that the current market and regulatory structure does not provide sufficient certainty to promote supply-side investments in major, new electric generating facilities, especially baseload facilities. Michigan’s retail choice program and the market-based regional wholesale markets have contributed to this risk. Michigan needs to address this dilemma soon, because Plan modeling shows that to maintain system reliability and assure future electricity affordability, Michigan needs to add generation or alternative resources in the near term. Most participants support some form of legislation providing the Commission with authority to establish procedures to ensure that new electric generating plants will be added to the state’s generation mix when needed.

Subsection 2.3 presents the central station policy proposals offered by Plan participants, and Subsection 2.4 discusses major issues related to the acquisition of central station resources. Staff conclusions and recommendations are then presented in Subsection 2.5.

2.3 Central Station Policy Proposals, 21st Century Energy Plan Participants

The Central Station policy discussion began with various participants submitting strawman policy proposals intended to address shortcomings in Michigan’s hybrid market. Originally, four
Central Station strawman policy proposals were developed. Subsequently, three of the strawman proposals, which had similar approaches, were combined by participants, into one strawman proposal.

The two resulting proposals began with similar approaches. Both recommend each utility prepare and file an integrated resource plan (IRP) to determine its generation needs. They also recommend the IRP analyze a broad set of resources to address additional generation need. The resource mix includes central station generating units, energy efficiency, renewable energy, load management, wholesale market opportunities, and transmission expansion. The proposals disagree on whether the filing should be mandatory and on a regular basis, or only when a utility seeks to add generation.

Each proposal advocates a two-step Commission process: one proceeding to review resource need and the proposed capacity bidding process, which may result in Commission certification for the need of baseload generation and guidelines for subsequent capacity bidding, and a second phase for the bidding process to acquire the needed capacity. The bidding process would incorporate all the Commission requirements from the first administrative step. All proposals recommended a contested case process. Elements of the proposals’ first phase are summarized in Table 3.

There are numerous differences in detail between the two strawman proposals, but two differences are critical. These two differences are (1) capacity ownership options under the capacity bidding process and (2) the framework for “obligation to serve” in the state’s customer choice program.

### 2.3.1 Capacity Ownership Options under the Capacity Bidding Process

**Strawman 1 requires competitive bidding for any capacity** – If the Commission deemed a baseload plant necessary to meet a utility’s future energy demand, Strawman 1 would require the utility to issue an request for proposal (RFP) to give independent power developers the opportunity to bid on building, owning, and operating the plant, or supplying equivalent power to the utility under a power purchase agreement (PPA). Based on the bids, the Commission would determine whether the utility would be allowed to build the plant that would serve its customers, or whether an independent power producer could provide the power through a PPA. In this Commission review, the utility would be treated in the same manner as all other interested or potential project developers.

Bidding standards would be established by the Commission, which would have 180 days to adopt a bidding format for the draft RFP, including evaluation criteria and standard contract terms. Bidding standards would govern utility participation and provide for independent evaluation of the bids, binding price caps on bids, rules for contesting the bids, confidential bids, and rules for allocating risks between ratepayers and project developers. The standards would also provide for all source bidding with a preference for cost effective energy efficiency and renewable energy options.
Table 3: Central Station Strawman Proposals

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Strawman #1</th>
<th>Strawman #2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule Long Term Forecast Resources</td>
<td>• Mandatory – every two years</td>
<td>• When needed</td>
</tr>
<tr>
<td></td>
<td>• Entire service territory and wholesale customers identify choice sales</td>
<td>• Full service customers</td>
</tr>
<tr>
<td></td>
<td>• Central station generation</td>
<td>• Central station generation</td>
</tr>
<tr>
<td></td>
<td>• Energy efficiency</td>
<td>• Energy efficiency</td>
</tr>
<tr>
<td></td>
<td>• Renewable energy</td>
<td>• Renewable energy</td>
</tr>
<tr>
<td></td>
<td>• Load management</td>
<td>• Load management</td>
</tr>
<tr>
<td></td>
<td>• Transmission expansion</td>
<td>• Transmission expansion</td>
</tr>
<tr>
<td></td>
<td>• Regional generation sources including MISO markets</td>
<td>• Existing generation from within region</td>
</tr>
<tr>
<td>Bidding</td>
<td>• Required to bid need to include all market participants</td>
<td>• Bid engineering, procurement construction (EPC)</td>
</tr>
<tr>
<td></td>
<td>• All source bid, with first allocation to all cost effective energy efficiency and renewables</td>
<td>• Energy supply plan</td>
</tr>
<tr>
<td>Cost Allocation</td>
<td>• Overruns borne by developers and utilities</td>
<td>• Option: would allocate cost overruns to utility for higher rate of return</td>
</tr>
<tr>
<td></td>
<td>• No cost recovery prior to in-service date</td>
<td>• Option: prudently incurred costs recovered</td>
</tr>
<tr>
<td></td>
<td>• Maintain current return to service provisions</td>
<td>• Return to utility service at negotiated rates, no obligation to serve returning customers</td>
</tr>
<tr>
<td>Customer Choice</td>
<td>• Analyze alternative reliability targets</td>
<td>• Choice suppliers must meet reliability standards</td>
</tr>
<tr>
<td>Other</td>
<td>• Deskew rates</td>
<td>• Preapproval through Certificate</td>
</tr>
<tr>
<td></td>
<td>• Determination of capacity for reliability or economic reasons</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Preapproval granted</td>
<td></td>
</tr>
</tbody>
</table>

Strawman 2 also recommends competitive bidding, but only for engineering, procurement, and construction (EPC) of a utility owned power plant – EPC represents an estimated 85 percent of a new plant’s construction costs. In this case, the utility would submit a resource plan to the Commission, detailing its plans to use energy efficiency, renewable energy, transmission, existing regional resources, and new generation to meet its customers’ needs. If the plan includes a new generating unit, the utility could request a Certificate of Need. The Commission would have 180 days to issue or deny the request.

After the issuance of a certificate, the utility would be required to develop preliminary engineering specifications, a site analysis, and a detailed cost basis for the plant. The Commission would review the utility’s preliminary proposal, determine whether costs were prudent, and issue an irrevocable order authorizing need for the plant. Following a Commission order, the proposal would allow rate relief related to financing cost prior to commercial operation. Excess costs would be subject to Commission prudence review.
2.3.2 Framework for Obligation to Serve

Incumbent utilities’ “obligation to serve” in Michigan’s hybrid market was the second significant difference between the strawman proposals. Utilities presently have an obligation to serve all customers, but the customer choice program allows customers to take generation service from an alternative provider. The obligation to serve means customers can take service from an alternate electric supplier but return to a regulated utility’s generation service at a later date, at which time the utility must provide service to the returning customer.

**Strawman 1 asserts that the Commission’s current policy regarding return to full service does not need to be altered** – The policy, which proponents say should be codified, requires returning customers to inform the utility of plans to return by December 1 for the subsequent year. Otherwise, returning customers are charged market based costs through the summer. Returning customers must also remain with the utility for 12 months.

It initially appeared that Strawman 1 proponents anticipated that continuing stranded cost cases would be sufficient to protect utility plant investment. Discussions with some of these participants, however, indicated that they do not advocate continuing the Commission stranded cost process. Instead, some strawman proponents suggest that current ratemaking along with DTE’s impending choice incentive mechanism (CIM) protects the utility from the effects and risks of customer migration. As a result, they see no need to change current return to service provisions.

**Strawman 2 proponents argue retail choice gives alternative electric suppliers freedom to choose customers without an obligation to serve** – Alternative electric suppliers can avoid serving any customer or customer group, such as residential customers, who are small and expensive to serve, or customers with less desirable load shapes that are, therefore, more expensive to serve. In contrast, Strawman 2 proponents argue, utilities are obligated to serve all customers large or small, and customers with good or difficult load shapes. They also argue rates are not set at cost of service. As a result, the utility obligation to provide universal service, has added costs and burdens, and Strawman 2 proponents believe this current situation is inequitable.

Strawman 2 proponents assert utilities should not be obliged to serve at regulated rates those customers who leave for choice but later choose to return. These participants argue customers have no obligation to stay with the utility after resources have been purchased to serve them, creating an unfair obligation for the utility, which ultimately disadvantages its remaining customers. Therefore, under Strawman 2, once a customer leaves for choice, they should be able to return to the utility’s service but only at market prices or negotiated rates.

Strawman 2 proponents also argue choice suppliers should be required to meet the same reserve margin standards of regulated utilities, acquire ancillary services, and participate in energy efficiency and renewable energy programs. In addition, regulated rates for full service utility customers should be set according to cost of service calculations, according to this proposal. Without cost of service based rates, proponents say that incorrect signals are sent to market participants and alternative suppliers have the opportunity to selectively market to high margin customers.
customers. The proposal also calls for a circuit breaker to limit customer choice participation. The circuit breaker would be triggered if customer choice participation levels increased above a certain level.

Regulated utility rates would also be automatically adjusted to account for changes in electric choice participation by the LDC customers, under the Strawman 2 proposal. Finally, Strawman 2 advocates urge use of a wires charge to supply revenue certainty for new plant construction.

2.4 Major Issues impacting Central Station Resources

As noted previously, Michigan’s hybrid electric choice market is a major factor contributing to financial risk of any major investments in generating capacity. Each Strawman proposal seeks a solution to the current market situation by creating a capacity bidding framework and addressing return to full service issues. The following sections discuss issues related to the choice market, capacity bidding, and return to full service.

2.4.1 Michigan’s Retail Choice Market

Three market alternatives have been identified to address Michigan’s electric generation capacity needs. First, the market could be re-regulated by repealing retail choice under Michigan 2000 PA 141 (PA 141; MCL 460.10 et seq the statutory revision that created the electric customer choice program. Second, the market could be fully deregulated and regulated utilities required to spin-off generation resources. And third, existing law could be modified to make Michigan’s electric market sustainable while balancing the interests of Michigan ratepayers.

With regard to these three alternatives, Staff: (1) believes re-regulating retail generation service is plausible, but takes no position on whether this action is appropriate; (2) strongly rejects complete deregulation; and (3) recommends modifying the current regulatory framework, to both maintain and refine Michigan's split-market retail model. The third recommendation emerged as the central theme expressed by Plan participants. It was the focus of the CNF Update Workgroup proposals and Staff’s response proposal.

Policy Options

Re-regulation – The Governor and the Legislature could reverse 2000 PA 141 and eliminate the uncertainty that it has created. Staff initially considered re-regulation as impractical. However, it has been pointed out that California, which led the nation in the deregulation movement, has already has suspended indefinitely, its retail choice option. Delaware, which likewise deregulated its electric generation market, has recently announced plans to study re-regulation after experiencing price increases in a volatile market. Ohio repeatedly extended price freezes on its ratepayers and deferred the implementation of competitive market prices for fear of rapidly escalating costs associated with its deregulated markets. In Illinois, the state rejected implementation of market based prices for its commercial and industrial customers served by

---

distribution companies as providers of last resort, after a supply auction resulted in bids of 8.5 - 9.0 cents/kWh. This price was deemed too high by the Illinois Commerce Commission.

Perhaps the most surprising turnaround on this issue is the position of the Electricity Consumers Resource Council (ELCON), a national association of large industrial electricity users. ELCON is in the forefront of advocating for competitive electricity markets. However, in a recent article, ELCON indicated that it continues to advocate for “real” competition, but then advises that today’s market structures cannot provide that competition. While ELCON indicates it would prefer modifying the current market structures, it seems doubtful that ELCON’s proposed changes would or could induce significantly different circumstances than those that exist today. ELCON recommends, among other things:

States that have not yet restructured should not do so: Roughly two-thirds of the states have not yet restructured or have begun the process but are not past the point of no return. They have the opportunity to wait until a wholesale market structure develops that can support retail competition and actually bring demonstrated benefits to consumers. . . . If today’s organized markets cannot be fixed, explore all options including a return to traditional regulation: If today’s organized markets – which are not a step toward competition but in truth a new form of regulation – are the best we can ever expect, large industrial electricity consumers are prepared to explore all options, including a return to regulation based on cost of service. We recognize that in states where local distribution companies have sold their generation this may be especially difficult and will take considerable time and effort. Our preference would be that the existing markets be fixed.

A recent study conducted by Public Sector Consultants for the Michigan Municipal Power Association concluded that Michigan’s current industry structure is a flawed attempt at market restructuring and is unsustainable. The report states:

What is clear, however, is that the currently partially deregulated status of 2000 PA 141 is not sustainable, does have an impact on reliability, and causes regulated utilities to operate in a less than efficient manner.

The report stresses that incumbent utilities have an obligation to serve all customers, but that alternative electric suppliers can pick and choose the most profitable customers to serve. According to the report:

If policymakers truly wish to have a competitive electric market in the state, they must be willing to allow the introduction of risk through the removal of the

---

22 For more information on Electricity Consumers Resource Council, visit http://www.elcon.org/.

obligation to serve at least for customers that leave regulated providers. This will, most likely, result in a less reliable but also more competitive and fairer electric market. If, however, policymakers are not willing to accept these risks then they should take steps that move the state toward a more traditional regulatory framework.  

The Staff’s position on reversing the effects of 2000 PA 141 is neutral; however, from a regulatory perspective, reversing 2000 PA 141 would have two effects: it should provide a remedy for the seeming inability to site and build new baseload plant in Michigan; and it would foreclose retail choice for customers who find it desirable or economic to buy electricity from alternative electric suppliers.

**Complete Deregulation** – The turmoil created by fully deregulated markets – most recently in Maryland where rates increased by 72 percent, in Illinois where residential rates have increased up to 55 percent, and in Delaware where rates increased by 59 percent – make a strong case for rejecting complete deregulation of retail generation services and/or divestiture of generation plants to market-based rates. Those states are the most recent examples of rapid cost increases following full deregulation.

Fully deregulating Michigan’s electricity market may lead to an unprecedented transfer of real economic wealth from ratepayers to the owners of the deregulated generation assets. A generating plant now priced at its actual, depreciated historical value would be allowed to price at market rates, significantly raising rates on all customers and undermining Michigan’s economy.

**Modify Current Framework** – Most of the Plan’s policy discussion centered on modifying Michigan’s current industry framework to address issues related to 2000 PA 141. Staff spent considerable time and effort last year in the Capacity Need Forum to develop a framework that could resolve the conflicts and difficulties associated with 2000 PA 141. That work was continued by participants and Staff in this Plan, as witnessed by the strawman proposals discussed previously. The remainder of Section 2 will discuss those attributes of 2000 PA 141 that Staff finds most problematic and in need of change and present Staff’s recommendations for modifying Michigan’s regulatory structure.

2.4.2 Michigan Market Flaws

The goal of 2000 PA 141 was to shift public policy and the regulated electric utility industry toward competition. The act encouraged vertically integrated utilities to join independent regional transmission organizations (RTOs) or to divest their transmission assets. One outcome of 2000 PA 141 was independent electric transmission companies that allow competitors of incumbent electric utilities access to wholesale power markets. By encouraging development of independent third party transmission to all parties and retail choice of generation suppliers,

---

2000 PA 141 encouraged the development and reliance on competitive electric markets and a movement away from traditional regulated electric utilities.

Michigan policymakers, however, did not adopt utility divestiture of generating assets nor the concept of universal competition at market based rates when they restructured Michigan’s electric industry. Consequently, the Michigan market under 2000 PA 141 offers customers the option of electric generation services by alternative electric suppliers at market-based prices or full generation service from their local utility under the traditional regulated rate model. Advocates of full deregulation criticized the policy, but it has kept Michigan prices affordable compared to states that required generation to be spun off and prices fully deregulated. The importance of maintaining regulated generation is evident from the recent experiences in Maryland and Illinois, which required utilities to divest their generation. Since generating plant costs have typically increased, unregulated prices have drifted upward over the past several years. Market prices have also increased because most new generating plants constructed over the past decade have been natural gas fueled units and excess baseload capacity in the region has been declining.

The ability of Michigan customers to move between regulated and competitive markets, however, creates an uncertain customer base for both electric utilities and alternative electric suppliers (AESs). This makes planning for expensive, long lived baseload generating units difficult and adds considerable financial risk to plant investment decisions. Market prices have soared over the past two years and, in response, more than 2,000 MW of customer load returned to utility service from alternative suppliers in Michigan. A major issue that arose is the responsibility of incumbent utilities to plan and construct generating plant for this load, when it may migrate again to the competitive sector.

Some new plant construction is in the early development phase, but only involving suppliers protected from the risks of deregulation. Wolverine Power, a generation and transmission cooperative, is considering plans to build a baseload facility in Rogers City. Wolverine differs from the investor owned utilities, however, because its members have retail tariff provisions providing for non-bypassable charges for the plant’s development costs. And, Wolverine Cooperative’s members, unlike the major investor owned utilities, have not lost customers to AESs.

Without regulatory changes to promote more certainty, most Plan participants agree that financing baseload generating plants on favorable terms is unlikely. It is also clear that an independent power producer is unlikely to build base or intermediate load plants without a long term power purchase contract with load serving entities in Michigan. Contracts could potentially be secured with a combination of Michigan’s municipal and/or cooperative utilities, which have not yet experienced customers migrating to AES competitors. Major utilities, however, are unwilling to sign contracts with independent power producers due to uncertainty of customer need, regulatory risk, and wholesale market price risk. Without a regulatory-out clause, power purchase agreements (PPAs) expose regulated utilities to the same uncertainty and risk as building a new generating plant. The combination of fixed PPA costs and customers who are free to migrate to AESs could lead to serious difficulties for a utility and its remaining customer base. As fixed costs need to be recovered from smaller numbers of customers, and thus lower
total sales, then the inevitable result would be higher rates, utility under-recovery, or a combination of the two. This conclusion remains unchanged from the CNF report.

Based on public comments and discussion with CNF and Plan participants, utilities are unlikely to add major baseload generating units in the current hybrid market. It is also clear independent power producers are unlikely to build new baseload facilities without long term PPAs with credit worthy parties, such as distribution utilities. Utilities, however, are unwilling to sign long term PPAs, which makes independent power projects unlikely. Moreover, because state policy encourages competition in the industry, it is conceivable, although undesirable, that utilities may simply forego new investment and rely on wholesale markets for a growing portion of their generation needs.

The relatively easy movement of customers between Michigan’s two markets also undermines the ability to finance new generating plant because it undercuts the long held regulatory principle of cost causation. This occurs because customers can move freely between the two markets without consequences, even when they cause costs to be incurred for their benefit. This relatively cost free migration creates a rate burden on customers who have no choice of suppliers.

Regulated utilities must provide power to all ratepayers, but AES suppliers are permitted to select customers that are profitable to serve and avoid those that are difficult or expensive to serve. For example, residential customers are thought to be relatively more expensive to serve when compared to commercial or industrial customers. To date, AES suppliers have not marketed to residential customers, and virtually no residential customers have had a choice of generation service providers. AES commercial and industrial customers, however, have a major benefit provided by the customers of the local utilities – the option of returning to regulated rates if market prices increase.

Since enactment of 2000 PA 141, Michigan’s experience has demonstrated that customers can migrate to an AESs to take advantage of temporarily lower market prices, causing the rates of customers who remain with the utility to increase. This occurred between 2001 and 2004, when market prices were at comparatively low levels. During this period, electric market prices were being set by excess baseload power in the Midwest region and by electric generation fueled by inexpensive natural gas. In 2004, Detroit Edison’s rates increased by $385 million, of which approximately $300 million was necessary to replace revenue lost for the 9,200 GWh of electric sales that migrated to the customer choice program. This $300 million represented fixed costs of maintaining the Edison system and was shifted to customers remaining with Edison from customers migrating to choice suppliers.

When wholesale market prices began a sustained increase through 2004, 2005, and 2006, customers who had previously migrated to the competitive choice market began to return to the utility’s regulated rates. To help serve these returning customers, the regulated utilities were required to purchase more expensive power in the volatile wholesale markets. This more expensive market power caused the incumbent utilities power supply costs to increase. The resulting rate increases were passed on to all customers, including those who had never left the utility for the choice program and even those who were never afforded an opportunity to leave.
Detroit Edison’s power supply costs have been estimated to have increased by $60 million to accommodate these returning customers in 2005.

The 2001 through 2006 period is a graphic example of the cost burden borne by full service customers, particularly residential customers, who have thus far had no opportunity to migrate to choice, caused by other customers seeking to take advantage of temporarily lower market prices. Departing customers have enjoyed the lower prices without incurring the risks and costs created by their decisions. Their decisions are made risk free by the option of returning to regulated rates and a generation system being maintained by other customers. This very option, however, creates the uncertainty that makes the Michigan system unsustainable.

Some participants suggested an automatic revenue recovery mechanism like DTE’s CIM would eliminate the risks of revenue loss due to customer choice. Automatic recovery programs that raise rates for customer migration however, can be counterproductive. They actually accentuate the risk of major plant construction or PPAs. With an automatic recovery mechanism, as customers leave, remaining customers’ rates automatically increase, as the higher fixed costs are spread over a smaller sales base, thereby providing a greater incentive for other customers to leave. Over the longer term, it is not clear that this type of mechanism would improve revenue certainty.

Finally, even as customers who move to an alternate electric supplier can avoid the cost of maintaining the regulated system, they benefit from additions made to that system. If a new baseload unit is constructed by a regulated utility, it serves to lower the locational marginal price to which all ratepayers are exposed, whether they contribute to the new plant or not. A new plant will also improve electric reliability for the benefit of all ratepayers. This is known as the “public good” effect and was discussed at length in the CNF. Even though choice customers are not required to pay for new generating units, they do benefit from the capacity that is added by regulated utilities. The Michigan market is not designed to recover the indirect benefit from construction of new plants, even though the benefits may accrue to both regulated utility customers and choice customers.

2.5 Staff Conclusions and Recommendations

2.5.1 Integrated Resource Plan and Certificate of Need

Staff agrees with the recommendation in both strawman proposals that a regulated utility seeking to build a new generating unit should first file an integrated resource plan (IRP). Staff recommends the IRP process, as described here, as one of two options available to a utility seeking to build a new generating plant. The other option would be the Commission’s traditional method of incorporating new generating plant into a utility’s ratebase, which occurs after a hearing which reviews a utility’s application for rate recovery after the new plant is completed and has become operational. The operative expression is that a plant has to be “used and useful” before its costs should be eligible for rate recovery.

In the IRP process option, the utility’s IRP should conform to standards adopted by the Commission. The IRP process would be conducted as a contested case, offering participants the
opportunity to review the utility’s assessment of its need for new generation, fully examine the utility’s proposal, and provide recommendations to the Commission.

The utility would be required to assess all reasonable options for meeting its capacity needs. This would include energy efficiency and renewable energy in its plan, with the appropriate level of investment in energy efficiency determined in a public hearing conducted exclusively for that purpose, and renewable capacity determined by the state’s RPS targets. The utility would also be required to assess load management options, and the availability and cost of external market purchase options including required transmission expenses. The IRP would also identify and examine major contingencies and explain why the utility’s preferred plan is the best plan for its customers.

After modeling the availability of all these resources and examining planning contingencies, the utility would need to demonstrate that a central station generating plant is needed and is an integral part of the best plan to meet its customers’ needs. For any new utility-owned generating plant, the utility would need to specify its cost, with as much accuracy as practical, including any required investments related to grid interconnection and transmission.

If the Commission agreed that additional generation was needed, this process would result in the Commission issuing a certificate of need. This certificate would be irrevocable, subject to the Commission’s normal appeals process. The certificate of need process would provide assurance to the utility and its investors that a plant would not be deemed imprudent afterwards, because of customer choice migration after the plant is constructed. The Commission could, however, scrutinize the prudence of costs incurred.

At its discretion, the Commission could extend its current policy regarding recovery of some or all of the construction financing costs during the construction. The Commission’s current ratemaking policy is to allow earnings on CWIP (no AFUDC offset) for pollution control equipment. A proposed extension of this policy would be at the Commission’s sole discretion. The extension would have to be requested by the utility as part of its financing plan. The Commission would not allow recovery of plant construction costs, until after the plant became operational.

Staff recommends this IRP process as one of two alternatives available to a utility seeking to build a new generating unit. The other alternative is the Commission’s traditional method of incorporating new generating plant into a utility’s rates.

### 2.5.2 Capacity Bidding Issues

**Capacity Bidding for New Utility Central Station Resources Requires Careful Consideration** – Strawman 1 suggests the Commission adopt rules to allocate risks among the developers, the utility, and the ratepayers. For example, any PPA resulting from a competitive bidding procedure may include provisions for future greenhouse gas emissions controls. Or, the bidding process might apportion risk by allowing for the pass-through to ratepayers of future costs. Alternatively, the PPA might place risks on the developer and, in response, developers would presumably raise bid prices.
Fuel cost is another significant risk factor. A PPA signed under a competitive bid process and sufficient to support construction is likely to be a long term contract. Bid prices related to the operating cost component might need to be tied to future fuel costs. These costs, however, cannot be known ahead of time, so changes in fuel costs might simply be passed through to customers, including regulated utilities, or a risk premium would have to be paid to the bidder for accepting the risk associated with future fuel costs.

These risks, along with other unforeseen risks, require that much care must be exercised in a competitive bidding process. It is not clear that all these risks and uncertainties can be identified in an RFP process. Some independent power producers (IPP) participants propose that the preferred way to handle these risks is to treat the IPP like a regulated utility. They reason that if the regulatory process allows a pass through of costs incurred by a utility, it should also allow a pass through of those same costs incurred by an IPP.

Regulated utilities, however, are subject to prudence review, and any attempt to pass through costs can be closely scrutinized and costs can be disallowed, if that is appropriate. IPPs, on the other hand, do not come under the Commission’s jurisdiction. The Commission cannot scrutinize costs incurred by these entities, nor can it penalize IPPs for engaging in imprudent practices by reducing their rates of return.

For some PPA generating plant options, like combustion turbines, bidding could be a straightforward process. These units are easy to site and have standard features. However, for major solid fuel baseload units, bidding is not as straightforward. Tradeoffs would need to be considered, in terms of cost, availability, unit efficiencies, fuel diversity, future fuel security, and future emissions requirements. Acquiring air permits and siting a unit can be problematic. The risk of delays must be apportioned between bidder and ratepayer, which is certain to lead to disagreements – whether it is apportioned up front in the RFP and contract, or in a subsequent prudency review.

Transmission interconnection requirements present another bidding dilemma. Strawman 1 participants noted cost and scheduling of new generating plant construction is now more uncertain due to MISO’s evolving interconnection policy and administrative procedures. Participants suggested an allowance be made for this uncertainty, but did not specify a method for allocating the associated risks.

A disadvantage of IPP construction of a new generating plant under a bidding framework is that the principal advantage – leveraged financing typically used by IPPs – could prove

---

25 Wolverine’s experience with the proposed Prairie States coal generating unit is illustrative: it has taken five years to secure the necessary air quality permit from the U.S. EPA Environmental Review Board. In the meantime, the plant’s estimated cost has escalated.

26 The cost and difficulties have recently been highlighted by Noble Energy’s experience in Michigan’s thumb area. Noble won an RFP bid with Consumers Energy before making arrangements for interconnections on its proposed facilities. The difficulty and cost of arranging the interconnections has set back the project’s completion date, and energy that Consumers had anticipated being supplied by the project is not yet available. Further, it is still not clear when the power may be available.
counterproductive. Highly leveraged financing can lower capital costs of a new generating plant by making extensive use of debt financing. However, according to a September 2005 presentation made by the Electric Power Supply Association (EPSA)\textsuperscript{27} to the CNF, rating agencies may view utility PPAs as a utility debt obligation. This would cause the required rate of return on all of a utility’s investments to increase due to the negative impact of additional debt. According to the EPSA presentation, states across the country have recognized the tendency of PPAs to be treated as a utility debt and have adjusted PPA bids accordingly. The treatment of a PPA as debt is likely for Michigan utilities because of the state’s customer choice program. Thus, the cost advantage for an IPP to build using highly leveraged construction secured by a PPA would be offset by transferring the risk and resulting financial burden onto the utility and its customers.

Many participants agree that comparing bids for major units is a complex and difficult exercise if properly done. It might require the Commission to assume risks for ratepayers up front, prior to the bidding process. This could include the assumption of risks that are not now apparent, and perhaps even risks that cannot be known or understood in advance. Ultimately, using competitive bidding to correct past utility plant construction errors, cost-overruns, and unforeseen fuel and environmental costs may be a remedy that cannot avoid a pass through of much the same risks, in one way or another, because financial markets and developers may not construct plants if they have to assume those risks.

Wolverine Power’s experience with the Prairie States project has caused it to conclude that the administrative and contracting complications and difficulties associated with bidding outweigh any benefits that might be derived from the process. Unlike an IPP, an investor owned utility, or project developers, Wolverine has no financial incentive to add a generating plant to its ratebase since it does not earn a profit on plant investments. From a financial perspective Wolverine should be indifferent to whether it builds or bids. But, Wolverine concludes that bidding may not lower its costs or reduce risks that need to be assigned to customers.

**Capacity Bidding Supporters** – Support for bidding stems from two sources of opposition to utility construction. First, some participants indicate utilities should focus on distribution service only and that 2000 PA 141 should have served as a transition to a fully competitive industry structure, including generation divestiture by incumbent utilities. As mentioned previously, the concern for affordable power and observations of rapid cost increases in states that have adopted this approach cause Commission Staff to consider this the least desirable policy change for Michigan and a threat to the state’s economic future.

Second, many participants are concerned with cost overruns or paying too much for a utility-constructed plant. Excessive costs associated with the Fermi II and Midland nuclear projects have not been forgotten. Some oppose utilities building any new generating plants. Others are indifferent as to who builds the next baseload generating unit, but lack confidence that incumbent utilities can do it at the lowest cost.

Competitive solicitation of power through a PPA is touted as a measure to assure reasonable costs. This option is alluring for a regulatory agency hoping to avoid unnecessary and unreasonable rate costs.

Staff surveyed other states to determine how prevalent competitive bidding has become as a method for acquiring resources. The results indicate that 12 of the 48 states surveyed require competitive bidding. The large majority – 35 states – requires regulated utilities and, in some cases IPPs, to obtain siting approval or certification of need from a siting board or regulatory commission prior to the construction of a new power plant. State laws and policies governing rate recovery for new generating plants vary considerably, from traditional, after-the-fact prudence reviews in rate cases to pre-approval of construction costs (13 states). An increasing number of states are allowing utilities to request prudence determinations or advanced ratemaking treatment prior to construction. In states where generation is deregulated (e.g., the Northeast, Texas, Illinois) cost recovery is left to market forces alone.

**Staff concludes that capacity bidding for utility generation conforming to the Strawman 2 proposal better balances risks for Michigan customers** – This proposal requires bidding for the EPC phase of new facilities and under this proposal the utility would own the plant, which would be eligible for ratebase treatment using conventional accounting.

While some participants strongly advocate the merits of competition in bidding for generation ownership, they seem to distrust its merits as a means of disciplining utility construction costs. Competitive markets allow customers to buy service from the low cost provider. If a utility invests too much money in a new generating facility, or fails to complete a project within schedule, it risks losing customers to competitive suppliers. Ironically, parties who support competitive bidding for capacity through PPAs and the need for competitive choice markets also distrust the ability of competition to discipline utility construction costs. Michigan’s hybrid market should help prevent excessive costs if a Michigan utility builds a baseload generating plant for its customers. If construction causes a utility’s costs to rise relative to wholesale market prices, unhappy customers can exercise their choice to leave the utility’s generation service.

Utilities indicate that approximately 85 percent of a new plant’s cost can be accounted for by the EPC contract, which Staff would require be competitively bid. Since most of a new plant’s cost would be subject to a competitive bid process, and customers have the option to leave the utility for a choice supplier, there seems little likelihood that competitive PPA solicitation could produce additional gain, especially given the difficulties with specifying all of the important attributes associated with a baseload plant RFP and allocating the associated risks among participants.

Under the Staff proposal, the risks of future uncertainty, such as fuel price and air emissions concerns, will be dealt with under the current regulatory framework. The Commission can also review a utility’s decisions and costs, and disallow any deemed imprudent.

Staff is wary of undertaking a contentious, complex appraisal of multiple bids that may result in litigation. Even without lawsuits, Staff is not aware that IPPs can or will finance projects where major risk factors are borne by the IPP and its financiers without increasing prices in the bid
Section 2

process to deal with these contingencies. Consequently, utility ownership represents no more risk to ratepayers than alternative strategies. Staff recommends that a competitive bidding option must be offered, but also recommends it should be limited to the engineering, procurement and construction work for a new plant.

Finally, Staff notes that utilities are free to make use of competitive bidding for PPAs. These contracts have already been used to secure long term and short term capacity needs. Staff does not recommend that competitive bidding PPAs be mandatory, however, for the reasons cited above.

2.5.3 Customer Choice Option

While the certificate of need process may reduce risks related to a new generating plant’s need, it would not remedy the rate burden on a utility’s full service customers caused by other customers migrating to the choice program. Instead, full service customers would be paying to maintain the regulated system that choice customers rely on if market prices increase or power becomes scarce. To more fairly balance the interests of various ratepayers, the opportunity of customers to choose an AES, and the need to provide more revenue certainty in order for a utility to be able to finance a new plant, Staff has developed a proposal based on the cost causation principle and centered on changes to the current return to service provisions that apply to electric choice customers.

If a utility seeks a certificate of need for a new generating plant and the certificate is granted, customers must choose whether they want to remain with the incumbent utility or take advantage of the customer choice program. Customers electing full service from the utility, therefore, are responsible, in part, for construction of the new plant. If those customers later elect service from an AES, they should take their pro-rata share of the plant’s fixed cost with them as a non-bypassable distribution charge.

If customers choose instead to take service from an AES when a utility applies for a certificate, they will not be responsible for the costs of the new plant, as long as they remain in the customer choice program.

Based upon recent cost increases caused by customers first departing for the customer choice program and then returning, Staff further recommends changes to the return to service provisions for those customers electing AESs. Those customers returning to a utility’s full service from the customer choice program should provide a two year notification of their return to regulated rates. Customers will be allowed to return to the utility’s generation service 60 days after notification of return is given, but the return will be at a “best efforts,” that is a market basis, until the two year notification is satisfied. The two year period will permit the utility adequate time to arrange the power supply necessary to serve the returning customer, rather than being required to jump into potentially volatile wholesale markets to secure the power in a manner that causes non-choice customer rates to increase. Once the two year notification is given, the customer must return to the utility’s full service.
This combination of assigning cost recovery to those customers who cause the costs to be incurred, and a return to service provision that does not unfairly burden customers who remain on regulated rates will contribute significantly to making the Michigan system more sustainable.

2.5.4 Cost Based Rates

Staff recommends modifying Commission policy to assure mandatory cost based rates for efficient functioning of the market – Maintaining both regulated utilities with an obligation to serve all customers and a competitive choice program requires ongoing program modifications that will continue to create uncertainty for regulated utilities and AESs. Minimizing the disruption caused by simultaneous operation of both markets over the longer-term requires providing market participants with information and regulatory certainty. Cost of service based rates are an important component of a longer-term, stable program.

Unless regulated utilities’ rates are set equal to their cost of service, customers will have an incentive to choose an AES supplier even when the supplier’s cost is greater than the utility’s cost to serve the customer. This incentive can cause the migration of significant numbers of high margin customers from the utility to AES suppliers, raising costs to residential customers who have no supplier choice, and creating uncertainty in forecasting capacity needs associated with the incumbent utilities’ obligation to serve. If utility rates are not cost based, migration of high margin customers will occur for reasons other than each parties’ competitive advantage in providing service. Future Commissioners will have to protect ratepayers who do not have an AES alternative to manage this migration, or raise rates for non-choice customers.

Rates for non-choice customers likely will be affected either by the migration of high-margin customers away from the utilities or by adjusting rates on a cost of service basis. In the absence of cost of service based rates, the Commission faces an ongoing need to review the financial impact of customer choice participation on customers who have no choice of suppliers. It may also be required to implement a stranded cost proceeding for the regulated utilities or raise the rates of customers who remain with the incumbent utility. Price signals based on cost of service are important to assure that migration to choice decisions are made on a rational economic basis. This should provide a more stable customer choice program because economic considerations would govern the decision to move from the utility to an AES supplier.

2.5.5 Mandatory Planning Reserve

Staff recommends modifying Commission policy to set a mandatory planning reserve standard for all load serving entities – In the CNF report, Staff asserted electric reliability has the characteristics of a public good. As a public good, it is not possible to prohibit someone from taking advantage of the reliability, even if they do not pay for it.

This has been the case in Michigan since electric restructuring has occurred. Electric reliability is secured through the provision of operating reserves and planning reserves. Although AES suppliers are required by MISO to maintain operating reserves, they are not required to carry planning reserves. The experience over the past two years has confirmed that AESs might meet the MISO operating reserves, but they have not demonstrated they carry planning reserves.
Their electricity supply does not appear to satisfy generally accepted reliability standards; rather, the implicit conclusion is that they are simply relying on total system reliability for backup.

Generation planning reserves provide a critical backup supply, to address major unit or transmission line outages for extremely hot weather, or unanticipated economic growth. As noted earlier, peak demand was forecast to grow at 1.2 percent for this year, but due to abnormally hot weather, actual peak demand grew about 3.3 percent based on Consumers Energy data, and 4.1 percent before interruptions based on Detroit Edison data.

Until the regional electric reliability organization establishes and enforces reliability standards equivalent to the standards adopted in this report, Michigan’s restructuring program should be modified to allow the Commission to require planning reserves or their equivalent for all utilities and AESs operating within the state.

2.5.6 Maintain Securitization Charge

Staff recommends that the current securitization charge placed on all customers should be maintained for market stability and to comply with 2000 PA 141 – Strawman 1 proponents assert that choice customers do not receive a benefit for securitization charges. They do not support changes to the return to service provisions currently operative in the Michigan market. There appears to be widespread recognition by Plan participants, however, that securitization was a non-conditional component of Michigan’s restructured electricity market. No one has suggested that any benefit was intended to follow this payment, other than creation of the choice market. This issue has become prominent among some participants because market prices have risen, adding to the cost of AES service. Staff does not recommend revisiting this issue.

2.6 Summary of Central Station Power Plant Policies

Staff’s proposal for remedying the risks and uncertainty created by Michigan’s hybrid market structure includes a transparent, public process for evaluating a utility’s resource plan when a new generating unit is needed. Financial risk related to customer choice is ameliorated by recognition of the need for the unit even if future customer migration occurs. The utility must demonstrate that it has a viable plan for financing the plant. Staff also proposes a requirement that customers who cause the plant to be needed must contribute to the plant’s cost recovery, and altered return to full service provisions that allow sufficient time for a utility to arrange reasonable power supply. Cost of service based rates will promote more rational customer decisions regarding service choices, electric reliability will be preserved through new Commission authority to require adequate reserves and securitization should not be revisited.