Benton PUD Credit Exposure by Sector as of November 30, 2019

- Bank: $1,247,838
- IOU Affiliate: $86,944
- RTO: $24,908
- Integrated Oil & Gas Companies: $0
- Marketer/Merchant: $1,101,104
- IOU: $1,465
- Muni/Coop: $93,257

Benton's total exposure (principal and agent) is $2,555,516
Unrestricted Reserves and Days Cash on Hand (DCOH)

Unrestricted Reserves as of January 1, 2019 Treasurer's Report*

Total Reserves: $56.4M
Estimated 2019 $ per 1 DCOH: $391k
Total DCOH: 144

*On January 8, 2019, the Commission approved redistributing the Undesignated Reserves to Designated Reserve accounts

Unrestricted Reserves as of December 31, 2019

Total Reserves: $41.4M
Estimated 2019 $ per 1 DCOH: $410k
Total DCOH: 101

DCOH calculation from January 2020 forecast

Proposed Redistribution of Unrestricted Reserves

Total Reserves: $41.4M
Estimated 2020 $ per 1 DCOH: $397k
Total DCOH: 105

DCOH calculation from January 2020 forecast
Motion: Set the unrestricted reserves fund account balances to the following: Designated Special Capital Fund $0.00; Power Market Volatility $1,229,168.70; and the Undesignated Reserves $0.00.
COMMISSION MEETING AGENDA ITEM

Subject: Contract Award Recommendation for Contract #19-51-04 – Morgan Stanley Capital Group, Inc.

Agenda Item No: 

Meeting Date: January 14, 2020

Presented by: Kevin White

Approved by (dept): Rick Dunn

Approved for Commission review: Chad B. Bartram

Motion for Commission Consideration

Motion authorizing the General Manager on behalf of the District to sign a contract and all related documents with Morgan Stanley Capital Group, Inc., Contract #19-51-04, in substantially the form presented, to purchase a seasonal capacity product for 75MW heavy load hours (HLH) July/August and 25MW HLH December/January/February for a term of December 1, 2022 through August 31, 2025 at a not-to-exceed amount of $2,725,290.

Background

The District adopted its last Integrated Resource Plan (IRP) on August 14, 2018. The 2018 IRP Action Plan identified continuing to make market purchases for energy and capacity as the short-term preferred portfolio; however, it recognized the District has sizeable capacity deficits once the Frederickson contract expires in September 2022 and recommended considering longer term (3-5 year) capacity products in periods where the Northwest Power and Conservation Council ("Council") is projecting a Loss of Load Probability (LOLP) of greater than 5%. The Council’s 2024 Resource Adequacy Assessment reference case showed a 7% to 8% LOLP beginning in 2021 and specifically 8.2% and 17.0% in 2024 and 2026 respectively. The Council’s Assessment also acknowledged the potential for an early retirement of a 530MW coal plant that would increase the reference case LOLP to 12.8% and 26.0% in 2024 and 2026 respectively. Since the Council’s resource adequacy metrics were greater than 5% LOLP, it prompted staff to investigate longer term capacity products to cover a portion of the District’s summer and winter capacity deficits.

The 2018 IRP Action Plan also included an action item to develop a tactical plan for future purchases of capacity products from the market. The District contracted with The Energy Authority to conduct a capacity analysis and to engage in a product and price discovery effort for regional capacity products. TEA identified seasonal capacity products that could meet the District’s capacity needs from the time the Frederickson contract expires through 2025. TEA identified an average heavy load hour (HLH) deficit of 100MW in July/August and 45MW December/January/February. TEA’s recommendation is to purchase 75 MW for July/August and 25MW for December/January/February from December 2022 through August 2025 and
continue to utilize the District’s Risk Management Committee process to purchase the remaining deficit from the market. This strategy allows room for diversity in the District’s portfolio and allows for purchases of potential new, regional capacity resources, possibly natural gas resources, in the future and would allow for a 20-year project life (2025-2045) leading up to the 100% carbon free requirement beginning in 2045 under the Washington State’s recently adopted Clean Energy Transformation Act (CETA).

District staff reviewed TEA’s capacity analysis and agreed with their capacity purchase recommendation. Staff recommended to the Commission on October 8, 2019 to issue a request for proposal (RFP) as soon as practicable with the necessary due diligence for the following contract terms:

<table>
<thead>
<tr>
<th>Product</th>
<th>Term</th>
<th>Seasonal Months</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>WSPP Schedule C</td>
<td>December 2022</td>
<td>July/August</td>
<td>75MW HLH</td>
</tr>
<tr>
<td>Firm Capacity/Energy</td>
<td>to August 2025</td>
<td>December/January/February</td>
<td>25MW HLH</td>
</tr>
</tbody>
</table>

The Commission passed a motion aligned with staff’s recommendation and staff issued an RFP on October 24, 2019 with responses due by November 14, 2019. The District received three responses to the RFP and the District’s Power Risk Management Committee reviewed/evaluated the responses. Morgan Stanley Capital Group Inc. had the lowest capacity and energy prices of the three responses and met the District’s requirements for the seasonal capacity product. MSCG proposed a capacity charge of $3.75 per kW-month and an energy charge of ICE Mid-C Day Ahead Peak Index Mid Price plus $0.70 per MWh.

District staff reviewed the initial RFP results with the Commission at the November 26, 2019 Commission meeting and discussed beginning negotiations with MSCG. Staff provided an update on the progress of contract negotiations at the December 10, 2019 Commission meeting.

**Summary**

Purchasing a seasonal capacity product from MSCG reduces the District’s power supply risk by having a firm, physical resource it can call on if the market does not have adequate supply during the District’s highest deficit months.

**Fiscal Impact**

The cost of capacity will be $843,750 per year for a total of $2,531,250 for the three-year term. The incremental cost of energy (cost above Mid-C Index) is dependent on how often the District calls on the resource and could range from $0 (resource not called on) to $194,040 (resource called on 100% of the time) for the three-year period.
<table>
<thead>
<tr>
<th>Description</th>
<th>Small (SGS)</th>
<th>Medium (MGS)</th>
<th>Large (LGS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand (kW) per year</td>
<td>&lt;50 kW all year</td>
<td>&gt;50 kW at least once per year but</td>
<td>&gt;300 kW at least 3 times per year</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;300 kW at least 10 times per year</td>
<td></td>
</tr>
</tbody>
</table>

**General Service Current Structure and Criteria**