185. DOE's study indicates that further investigation of the substantial escalation of SPS's A&G and distribution O&M expenses is warranted.

186. SPS should be required to investigate (including work with affiliates regarding their charges) and to detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M costs, steps being taken to reduce them, and the timing and cost impact of those steps.

Fleet Fuel Expense

187. Fleet fuel expense reflects the costs that SPS incurs to purchase gasoline and diesel for its fleet of vehicles.

188. SPS's fleet fuel expense during the Test Year was $5,054,776.

189. Staff proposed to make an adjustment to the Test Year level of fleet fuel expense to reflect the reduction in fuel costs since the end of the Test Year.

190. Staff's proposed adjustment to fleet fuel expense is not known and measurable because fuel prices fluctuate, and it cannot be determined what fuel prices will be during the time the rates set in this case are in effect.

Renewable Energy Credits

191. SPS accrues renewable energy credits (RECs) in connection with purchases of renewable energy.

192. SPS obtains RECs through five long-term purchased power agreements, of which one is unbundled (*i.e.,* the prices of energy and RECs are separately stated) and the other four are bundled.

193. Currently, (1) SPS's revenues from sales of its RECs are a credit to eligible fuel expense; (2) for SPS's bundled purchased power agreements, the imputed value of the RECs is deducted from the total contract price in eligible fuel expense; and (3) SPS's costs for unbundled and bundled RECs are included in base rates.

194. In this case, SPS proposed to continue recovering REC expense in base rates; to continue allowing REC sales revenues to be credited through fuel expense; to continue allowing each state commission to establish the value of RECs generated in that state; to reduce the imputed price of bundled RECs from $1.10 per REC to $0.95 per REC; and to share margins from REC sales on a basis of 90% to customers and 10% to SPS.

195. SPS's proposals to continue recovering REC expense in base rates and to continue allowing each state commission to establish the value of RECs generated in that state are reasonable.

196. A price of $0.64 per bundled REC is reasonable and should be imputed to bundled RECs going forward.

197. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not show good cause to make an exception to that rule. REC sales credits should instead be included in SPS's base rates.

198. A base rate credit for REC sales revenues of ($207,792) is reasonable.

199. SPS did not prove that its proposal to allocate margins from REC sales on a basis of 90% to customers and 10% to SPS is reasonable or necessary or would produce any net benefit to customers.

Advertising, Contributions, and Dues

200. The Commission allows recovery for ordinary advertising, contributions, and donations as a cost of service as long as the sum of such items does not exceed three-tenths of 1.0% of the gross receipts for services rendered to the public (a 0.3% cap). 16 TAC § 25.231(b)(1)(e).

201. SPS's total advertising, contributions, and dues expense, without the 0.3% cap, reduced by the ALJs' adjustment of $686,619, is reasonable.

Amortization Expense for Regulatory Assets

202. SPS's proposal to include $1.5 million of historical energy efficiency expense in the cost of service is reasonable and consistent with the Commission's orders in prior SPS base rate cases.

203. SPS's proposal to include $2.8 million of historical REC expense in the cost of service is reasonable and consistent with the Commission's orders in prior rate cases.

204. SPS's proposal to include $34,898 of regulatory meter cost in the cost of service is reasonable.

Rate Case Expenses

205. SPS initially proposed to include in cost of service $2,521,940 of unamortized rate case expenses incurred in two prior SPS dockets, along with the amount of rate case expenses incurred or expected to be incurred in this docket.

206. SPS further proposed to offset those amounts by the remaining unamortized balance of the gain on sale of assets to Lubbock Power & Light, which was $2,226,277, and by the remaining unamortized balance of a credit attributable to the TUCO, Inc. overcharge, which was $83,753.

207. On March 6, 2015, the ALJs severed issues relating to the rate case expenses incurred in this docket and moved them to Docket No. 44498, which left the $2,521,940 of rate case expenses from prior dockets to be addressed in this case.

208. SPS proposed that the Lubbock Power & Light and TUCO, Inc. amounts be offset against the $2,521,940, which leaves a net rate case expense balance of $211,911.

209. It is reasonable to offset the Lubbock Power & Light and TUCO, Inc. amounts against the rate case expenses from prior dockets.

210. The $211,911 is a one-time expense. To avoid possible over-recovery, it should be recovered not through base rates but rather through a rider set to recover that specific amount.

211. Because $211,911 is a relatively small amount and Docket No. 44498 is pending, that amount should be recovered through the rider approved in that docket.

212. Consistent with Commission precedent, SPS should not be allowed to earn a return on unpaid rate case expenses.

213. An opportunity to challenge the reasonableness of SPS recovering the $211,911 was provided in this case. SPS proved that it should recover that amount, and that issue should not be re-litigated in Docket No. 44498.

Miscellaneous Services Revenue

214. SPS's proposal to include approximately $990,000 of miscellaneous services revenue in the cost of service is reasonable and should be approved.

Pole Attachment Fee Revenue

215. SPS included in the cost of service a credit of $1,377,041 to reflect the amount of pole attachment revenues SPS received in the Test Year.

216. SPS agreed that it is appropriate to increase the pole attachment revenue by $413,379 to reflect a normal amount of pole attachment revenues.

217. It is reasonable to include $1,790,420 of pole attachment revenues in the cost of service.

Interest on Customer Deposits

218. SPS calculated interest using the Commission-approved customer deposit interest rate of 0.09% per annum.

219. Effective January 1, 2015, the Commission-approved customer deposit interest rate fell to 0.07% per annum.

220. It is reasonable to use the updated customer deposit interest rate, which reduces the customer deposit interest balance by $1,627.

Uncollectible Expense

221. SPS requested recovery of $3,910,703 in uncollectible expense based on the Test Year amount of uncollectible expense recorded in FERC Account 904.

222. The Test Year level of expense is representative of the amount of uncollectible expense that SPS is likely to experience in the future. It is reasonable to include that amount in the cost of service.

Taxes

223. SPS inadvertently omitted the Research and Experimentation credit from the calculation of income tax expense.

224. It is reasonable for the Research and Experimentation credit to be included in the calculation of income tax expense.

225. A Research and Experimentation credit in the amount of $330,071 (total company) should be included in the cost of service.

226. SPS incurs property taxes in each jurisdiction in which it has tangible assets, including production plant, transmission plant, distribution plant, and general plant.

227. SPS made several adjustments to the Test Year property tax expense, including an adjustment to bring the property balances to June 30, 2014.

228. The property tax expense included in the cost of service should be calculated based on the plant balances as of the end of the Test Year.

229. It is reasonable to use actual property tax balances from 2014 to determine the ratio of tax to plant balances.

230. Property taxes attributable to CWIP should be capitalized to CWIP rather than charged to the current period operating expense. Capitalizing those property taxes to CWIP is reasonable and in compliance with the FERC Uniform System of Accounts.

231. Total company property tax expense should be calculated by reflecting the actual 2014 property-tax-to-plant ratio applied to the June 30, 2014 plant in service balance, exclusive of CWIP. Thus, the reasonable level of total company property tax expense is $29,723,945.

232. SPS's PUC assessment tax should be removed from FERC Account 928 and reclassified into FERC Account 408, because the PUC assessment tax is a gross receipts tax.

Baselines

233. It is necessary to set baselines for the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor.

234. Consistent with the Commission's initial findings in this proceeding, SPS filed revised calculations of the Transmission Cost Recovery Factor, Distribution Cost Recovery Factor, and Purchased Power Cost Recovery Factor baselines for review and comment by the parties.

235. The baselines set forth in Exhibit __ to this Order reflect the Commission's decisions in this case.

Miscellaneous Preliminary Order Revenue Requirement Issues

236. SPS's requested level of fees for the letter of credit that SPS posts for participation in SPP's transmission congestion rights auction is reasonable.

237. SPS has complied with all requirements of the Commission's final order in *Application of Southwestern Public Service Company for Authorization to Refund Amounts Received from Tri-County Electric Cooperative, Inc. Associated with Docket No. 42004*, Docket No. 44609, Order (July 2, 2015).

Present Revenue

Weather Normalization Adjustment

238. It is reasonable for SPS to calculate its normal weather based on a 10-year period in order to be consistent with the Commission's decision to use a 10-year period in the most recent SWEPCO base rate case, *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443.

239. SPS used weather data in developing its model to calculate the weather normalization adjustment that adequately represented the weather in SPS's service area.

240. The Test Year heating degree days were 9.7% above normal, the Test Year cooling degree days were 6.5% above normal, and the Test Year precipitation was 13.4% below normal.

241. It is reasonable for SPS to adjust its Test Year sales for certain customer classes to remove the effects of abnormal weather, and to use its model to calculate the adjustment.

242. It is reasonable for SPS to exclude the Test Year from the time period used to develop normal weather because including the Text Year creates a bias in the weather variance analysis.

Annualized Revenue for Transmission-Level Customer 8

243. SPS properly included a known and measurable adjustment, increasing the Test Year billing determinants to reflect Customer 8's increased usage after the customer installed a second transformer to provide service to additional processes at that customer's facility.

Adjustment to Post-Test Year Billing Determinants

244. SPS properly adjusted the Test Year billing determinants to reflect known and measurable changes through December 31, 2014.

245. SPS properly matched the billing determinants with the period of post-Test Year plant adjustments, and it updated the customer class allocation factors to reflect the calendar year 2014 information.

Inter-class Cost Allocation

Demand Allocation

246. It was reasonable for SPS to use the Production Demand (DPROD) allocation factor to allocate production costs among customer classes.

247. The DPROD allocation factor was developed using the line-loss adjusted Average and Excess 4 Coincident Peak Demand (AED-4CP) at the monthly peak for the four peak months of June through September.

248. For the allocation of most transmission costs among customer classes, SPS used the transmission demand (DTRAN) allocator, which was also developed using the line-loss adjusted AED-4CP at the monthly peak for the four peak months of June through September.

249. It was necessary to calculate separate AED-4CP allocation factors because SPS's production demand is somewhat lower than its transmission demand.

250. Class AED-4CP weights average demand by the SPS system load factor and excess demand by the inverse factor (1 – SPS system load factor).

251. To calculate the system load factor, SPS first divided annual kWh usage, adjusted for losses, by 8,760, the number of hours in the Test Year, which produced the average demand for the system. It then calculated the average of the coincident peaks for the four peak months of June, July, August, and September (4CP demands) and divided the average demand for the system by the 4CP demands, which produced the system load factor.

252. The 4CP demands should be calculated using the actual rather than the adjusted peak demands from the four summer months.

253. SPS properly considers more than a single peak hour when it plans and designs its generation resources and transmission systems.

254. Given the characteristics of SPS's system, using the single hourly annual peak to calculate the system load factor is unreasonable because it puts too much emphasis on one hour.

255. It is reasonable to use the 4CP demands to calculate the system load factor because: (1) it balances the average and excess demand on SPS's system and is consistent with cost causation principles; and (2) the Commission calculated the system load factor based on 4CP demands in Docket No. 40443.

256. SPS's demand allocation should be based on 4CP demands because SPS's peak season occurs over the four months of June through September, and each of the monthly peaks for those four months represents either the annual peak or is within 5% of the annual peak.

Radial Lines

257. Radial lines are not part of SPS's looped system, but are rather lines through which power flows in only one direction, to a limited number of customer classes.

258. In the last five rate cases filed by SPS in Texas, SPS has allocated the costs of each radial line based on the overall relative usage for the specific customer classes that use the line (but not those that did not use the line).

259. SPS knows which customers use the radial lines and which do not, and has some data regarding the relative loads each class taking service from each radial line puts on such lines.

260. SPS's proposal to allocate the costs of radial lines that serve more than one class to all classes based on the DTRAN allocator will unreasonably result in the costs of radial lines shifting to classes that do not take service from those lines.

261. Allocating the costs of radial lines that serve more than one class to each of those classes as a whole does not result in locational transmission pricing.

262. Radial lines are not considered part of the bulk electrical system in the SPP, and the costs of radial lines are directly assigned to each SPP member.

263. Under FERC rules, which govern wholesale costs of utilities in the SPP, radial lines provide distribution service rather than transmission service and would not be allocated to transmission level loads.

264. For radial lines that serve a single customer class, it is reasonable to allocate the cost of that line to only that class using the DTRANRAD allocator.

265. It is more reasonable and more consistent with cost causation principles to assign costs of radial lines that serve more than one class to only the classes that take service from those lines relative to their AED-4CP transmission demands, rather than allocating those costs to all classes using the DTRAN allocator.

General Plant and Intangible Plant

266. It is reasonable to allocate General and Intangible Plant (G&I Plant) costs among classes primarily on the basis of Salaries and Wages Excluding Administrative & General (SALWAGXAG).

267. The use of a labor allocator, such as SALWAGXAG, is consistent with cost-causation principles because G&I Plant costs are driven largely by the needs of employees.

268. The National Association of Regulatory Utility Commissioners Cost Allocation Manual contemplates the use of a labor allocator for G&I Plant costs.

269. The Commission's rate filing package for transmission and distribution utilities is not a rule and does not apply to vertically integrated utilities such as SPS.

270. Because G&I Plant is driven primarily by labor, SPS appropriately used the SALWAGXAG allocator to allocate those costs among the classes.

Miscellaneous Revenue

271. It is reasonable to allocate revenue from miscellaneous service charges and returned check fees based on the distribution plant in service allocator because the charges originate from customers that take service at distribution voltage.

272. SPS's treatment of miscellaneous service charges and returned check fees is consistent with treating uncollectible expense as a system cost on the uncollectible expense side rather than as an expense attributable to a single class.

Mutual Aid

273. SPS provides mutual aid to other utilities to help respond to natural disasters.

274. Under mutual aid agreements between SPS and other utilities, SPS receives reimbursement for the assistance it provides.

275. It is reasonable to allocate mutual aid reimbursement to classes on a total plant basis.

Electric Vehicle and Fuel Tax Credit

276. SPS's allocation of electric vehicle and fuel tax credits as overhead costs based upon labor is reasonable.

Separating Residential Service and Residential Service with Electric Space Heating for Purposes of Allocating Distribution Costs

277. It is reasonable for SPS to allocate distribution costs separately to the Residential Service and Residential Service with Electric Space Heating subclasses based on each subclass's own non-coincident peak because the customers in each subclass have different usage characteristics.

Distribution Substations Allocator

278. SPS properly allocated the costs of distribution substations among customer classes based on a non-coincident peak allocator.

279. Distribution substations are built by SPS to transform transmission voltage and provide distribution voltage to customers taking service at distribution voltage in localized areas.

280. The substations do not serve transmission voltage customers.

281. The substations are not sized to handle the system peak, but instead are sized to handle the customer loads in specific localized areas of the system.

282. An non-coincident peak allocation better reflects the end-use load characteristics of the transformation provided at the substations and is, therefore, reasonably applied.

Account 368 – Distribution Line Transformers

283. It is reasonable to distinguish between capacitors and transformers for purposes of allocating costs within FERC Account 368.

Account 556 – System Control Dispatching-Generation

284. SPS incurs costs recorded in FERC Account 556 for system control and dispatching of the production system.

285. Load dispatching reflects SPS's operation of its production, transmission, and distribution systems.

286. Load dispatching is a daily operation that occurs throughout the year every hour of every day, and must meet reliability requirements during peak and low-demand times.

287. Peak demand usage is included in each class's average demand over the course of a year.

288. A 12CP demand allocator is based on the average coincident peak for each month of the year.

289. The 12CP demand allocator balances the requirement to dispatch load to meet average usage and the requirement to dispatch load to meet maximum annual peak demand.

290. SPS reasonably allocated system control and dispatching costs among customer classes based on 12CP demand in this case and, based on the daily nature of dispatching, average usage throughout the year is an appropriate method for allocation.

Accounts 561.1-.3 – Load Dispatch – Transmission and Account 581 – Load Dispatching-Distribution

291. SPS properly allocated transmission-related load dispatch costs recorded in FERC Account 561 using an average demand allocator.

292. It is reasonable for SPS to allocate distribution-related load dispatch costs recorded in FERC Account 581 using an average demand allocator.

293. SPS dispatches its system every second of every day throughout the year, at peak times and at low-demand times to ensure reliability of the SPS system.

294. Annual line loss-adjusted kWh represents the use of the SPS system throughout the year by a customer class.

295. When the annual kWh of each customer class is compared to other customer classes, the comparison represents each class's relative average use of the SPS system throughout the year, and is the appropriate method of allocating costs for dispatching the SPS system because the activity occurs all day, every day, all year long.

Regional Market Expenses (Accounts 575.1, .2, .5, .6, .7, and .8)

296. Regional market expenses refer to costs charged to SPS by SPP to defray the costs of administering the SPP Open Access Transmission Tariff and of operating SPP's Integrated Marketplace.

297. These expenses are caused by SPS's daily operations undertaken to provide transmission system reliability, which is important throughout the year, both at off-peak and peak demand times.

298. SPS properly allocated the regional market expense included in FERC Account 575 among customer classes based largely on the DTRAN allocator because the majority of these costs represent charges from SPP that are based on transmission peaks.

299. SPS properly allocated smaller amounts of regional market expense according to an energy allocator because such method weights the allocation on the basis of usage throughout the year, including during peak times.

Account 593 – Distribution Maintenance of Overhead Lines

300. Most vegetation management relating to overhead lines in SPS's system occurs on the primary distribution system.

301. In numerous areas of SPS's system, there are secondary lines under the primary lines.

302. SPS's guidelines indicate that the company does not conduct routine pruning on secondary lines.

303. Even if the secondary system occasionally benefits from tree trimming done on SPS's primary system, the secondary system did not cause the expense of such trimming.

304. The costs of vegetation management relating to overhead lines in the SPS system which are caused by the secondary system are very minimal.

305. Allocating vegetation management costs between the primary and secondary distribution systems based on total overhead plant costs does not tend to promote cost of service-based rates.

306. It is more reasonable and consistent with cost causation to classify vegetation management costs as 98% to the primary distribution system and 2% to the secondary distribution system.

Account 902 – Meter Reading Costs

307. SPS reasonably allocated meter reading costs based on a weighted customer count that reflects the number of meters that can be read in a day.

308. A weighted customer count is appropriate because a greater number of meters can be read in the same interval of time for more generally concentrated customer classes such as residential, small commercial, municipal, and school customers, as compared to more spread-out customer classes such as larger demand-metered Commercial and Industrial (C&I) customers.

309. SPS's methodology for determining how many meters can be read in a day was reasonable.

Account 904 – Uncollectible Accounts

310. SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.

311. Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.

Major Account Representatives (Account 908 – Customer Assistance Expenses and Account 912 – Demonstrating and Selling Expenses)

312. SPS employs major account representatives that serve large customers in the C&I classes (Secondary General Service, Primary General Service, and LGS-T classes), but not customers in the Residential and Small General Service classes or smaller customers in the Secondary General Service class.

313. Assigning a weighting factor of ten to the Primary General Service and LGS-T classes was appropriate to reflect that smaller Secondary General Service customers are not typically served by these representatives.

314. SPS's proposal to allocate costs of major account representatives to the C&I classes (except for smaller Secondary General Service customers) is reasonable and consistent with cost causation principles.

Outside Services-Legal (Account 923)

315. SPS properly allocated the costs incurred in FERC Account 923 for outside legal services on the basis of the SALWAGXAG allocator.

316. It is reasonable to use the SALWAGXAG allocator because SPS engages outside counsel to perform only the work that exceeds the capacity of its in-house legal staff, and the costs of the in-house legal staff are allocated based on SALWAGXAG.

Contributions, Dues, and Donations

317. SPS reasonably allocated the costs of contributions, dues, and donations among customer classes using a labor allocator, SALWAGES, because contributions, dues, and donations are tied to employee activities.

Account 926 – Employee Pensions and Benefits

318. It is reasonable to allocate the employee pension and benefit costs recorded in FERC Account 926 among customer classes using the SALWAGXAG allocator, and the method matches the jurisdictional allocation method.

Historical Energy Efficiency Costs

319. Before 2012, SPS was not subject to the Energy Efficiency Cost Recovery Factor rule, and therefore it recovered energy efficiency costs in base rates.

320. In Docket No. 35763, a 2008 SPS base rate case, the parties agreed SPS would be allowed to recover the energy efficiency expenses incurred up to that time over a ten-year period.

321. Customers in the LGS-T classes did not receive services from SPS's historical energy efficiency programs prior to 2008, while the other classes did receive such services.

322. The LGS-T classes did not cause the costs incurred by SPS's historical energy efficiency programs.

323. Industrial customers such as those in the LGS-T classes have economic incentives to fund their own energy efficiency measures, at their own expense and to the benefit of SPS's system and other customers.

324. It is more consistent with cost causation principles to allocate SPS's historical energy efficiency costs to only the classes that received service from the programs, using an energy allocator.

Municipal Franchise Fees

325. SPS imposes two levels of municipal franchise fees: (1) a base level of 2-3% (depending on the franchise agreement) that is embedded in base rates and charged to all customers except for LGS-T customers located outside of municipal boundaries; and (2) an incremental amount that is collected from only the customers in the particular franchise jurisdiction charging the incremental amount.

326. Municipal franchise fees are incurred based solely on in-city electricity usage and the resulting revenues collected from those sales.

327. Based on cost causation principles, it is reasonable to allocate all municipal franchise fees on the basis of in-city revenues.

Determination of Customer Classes for Allocation and Rate Design Purposes

328. It is reasonable to adopt the following classes for purposes of cost allocation and revenue distribution in this case:

- Residential (including both Residential Service and Residential Service with Electric Space Heating, broken out separately);
- Small General Service;
- Secondary General Service (including Service Agreement Summary customers SAS-4 and SAS-8, as well as standby customers);
- Primary General Service (including standby customers);
- Large General Service – Transmission (69 kV);
- Large General Service – Transmission (115+ kV);
- Small Municipal and School;
- Large Municipal;

- Large School;
- Street Lighting; and
- Guard or Area Lighting.

329. The group of 11 classes is large enough to draw meaningful distinctions between customers based on their usage characteristics and the demands they make on the electrical system.

330. The group of 11 classes remains sufficiently general to avoid decomposition of costs and rates into specialized end uses.

331. In prior cases, SPS allocated costs to the customer classes as a whole using the AED-4CP allocation factor, with all costs allocated to the C&I classes considered together. SPS then distributed the revenue requirement to the C&I classes based on billing demand.

332. In this case, SPS reasonably allocated costs separately to the individual C&I classes using the AED-4CP allocation factors, and then it performed the class revenue increase distribution by calculating the class revenue targets based on that same approach.

333. SPS's allocation approach for the C&I classes will reduce the possibility of hidden subsidies between these classes and properly considers the differences between these classes concerning their effects on the SPS system.

334. SPS's allocation approach is reasonable because it allocates costs more consistently with cost-causation principles than the method it used in prior cases.

Revenue Distribution

Gradualism Adjustment

335. SPS's request that the maximum increase for any one class be capped at 200% of the system average increase, and that no class receive a rate decrease, is reasonable.

336. A 200% cap will move rates closer to a cost of service basis while accounting for valid concerns with respect to the cost of service methodology used by SPS.

337. A 200% cap will eliminate more inter-class subsidies than the previously proposed 150% cap, while still keeping adverse rate impacts under consideration.

Proposed Revenue Distribution

338. SPS's proposed revenue distribution is reasonable and consistent with cost causation principles.

Classes for Revenue Distribution in Future Cases

339. It is inappropriate for the Commission to determine parameters or requirements for rate classes to be approved in future base rate proceedings.

Rate Design

Customer Charge

340. The cost of service to the Residential Service class has increased, and therefore the service connection charge should also increase.

341. Increasing the service connection charge to the Residential Service class will reduce the amount of capacity costs caused by that class being paid by customers with higher load factors that use capacity more efficiently.

342. The full, component cost of service to a customer in the Residential Service class is $11.42 per month.

343. SPS's proposal to increase the monthly customer charge for the Residential Service class from the present charge of $7.60 to a proposed charge of $9.50 is reasonable.

Design and Future of Residential Service with Electric Space Heating Rates

344. SPS's request that the Residential Space Heating tariff be closed to new customers as of January 1, 2016 is reasonable.

345. Higher load factors in the winter months for Residential Service With Electric Space Heating customers would unreasonably result in moving rates for the Residential Service and Residential Service with Electric Space Heating subclasses classes further from cost causation principles if the winter discount for Residential Service with Electric Space Heating customers is not increased.

346. SPS's proposed $.05 per kWh increase in the winter discount rate for Residential Service with Electric Space Heating customers is reasonable and comports with cost causation principles.

Residential Time of Use Rates

347. SPS's proposal to offer an alternative, experimental Time of Use (TOU) rate rider for residential customers is reasonable.

348. The Residential TOU rate option will provide a reasonable alternative to future residential customers with electric space heating or other, significant non-summer consumption.

349. SPS will immediately begin communicating with its customers through bill inserts, website information, and direct contact from service representatives regarding TOU rates.

Small General Service

350. SPS's proposal to an increase the customer charge from $12.67 per month to $12.70 per month for the Small General Service customers is reasonable and reflects the actual customer-related cost for the Small General Service class.

Secondary General Service

351. SPS's proposed rate design for the Secondary General Service class is reasonable.

Primary General Service

352. Both Staff's and SPS's cost of service studies indicate that rates based on cost are higher for the Secondary General Service class than the Primary General Service class.

353. The rate differentials between the demand rates of the Secondary General Service class and the Primary General Service Class at other vertically integrated utilities in Texas are similar to the differentials between those two classes in SPS's cost of service study.

354. A widespread ratchet on Primary General Service customers may cause unreasonable adverse bill impacts on customers with significant off-peak seasonal loads or smaller customers in that class.

355. A demand ratchet would produce improper pricing signals for seasonal customers that have significantly higher loads during the off-peak non-summer months than during the summer months.

356. A demand ratchet may present difficulties for smaller Primary General Service customers that are similar to the kW demand billing difficulties for some Secondary General Service customers that the Rule of 80 is designed to assist.

357. It is not reasonable to establish a demand ratchet for Primary General Service customers.

358. It is not reasonable for SPS to adjust its revenue distribution by pooling the production, transmission, and primary capacity costs for the Primary General Service and Secondary General Service classes and allocating them according to billing demand.

359. It is reasonable and consistent with cost causation principles to allocate production, transmission and primary distribution capacity costs for the Primary General Service and Secondary General Service classes separately to each class according to billing demand.

LGS-T

360. SPS should not be required to present a primary transformation or primary substation service class or rate in its next rate case because such a class or rate is unnecessary.

361. It is inappropriate for the Commission to make decisions in this proceeding regarding rate classes for a future rate case.

362. SPS's current approach of leasing individual substations at replacement cost directly assigns substation costs to the very large customers that use each substation and is reasonable.

363. SPS's approach ensures that all costs from remote substations are recovered from the LGS-T customers that use them, and thus comports with cost causation principles.

Collection of Account 908 – Customer Assistance Expenses and Account 912 – Demonstration and Selling Expenses

364. Major account representatives are a service SPS makes available to its customers and is therefore a customer-related cost.

365. It is reasonable for SPS to recover part of this cost from the Secondary General Service class through a service availability charge and the rest through energy and demand charges.

Rule of 80 vs. Rule of 70

366. It is not appropriate or reasonable to revise Tariff Sheets Nos. IV-18, IV-175, and IV-182 to change the Rule of 80 to a Rule of 70.

367. Neither the Rule of 80 nor the Rule of 70 accounts for the timing of low load customers' maximum demand, so both could allow for billing reductions for usage during system peaks.

368. Moving from the Rule of 80 to the Rule of 70 will have a significant effect on the number of low load factor customers, including municipal customers, that will have to pay full demand charges.

369. The costs incurred by SPS as a result of the spikes of demand from low load factor customers at peak hours are considerably lower than the ordinary demand charge.

370. SPS load research data shows that low load factor customers have a very low coincidence with the system peak.

371. The Rule of 80 and the Rule of 70 are both generally cost of service based rates.

372. SPS did not show that moving from the Rule of 80 to the Rule of 70 will bring rates closer to cost of service.

373. It will take time to orient the low load factor customers to the experimental TOU and Low Load Factor rates, and it is unclear whether these rates will offer the same type of mitigation form overly high demand charges to the majority of these customers as does the Rule of 80.

Amarillo Recycling

374. It is reasonable to delete Electric Tariff Sheet No. IV-199 – the Service Agreement Summary applicable to ARC.

375. SPS is offering a Low Load Factor rate, which will be available to all customers served under the Secondary General Service class and the Primary General Service class that have a 25% or less average monthly load factor.

376. The proposed Low Load Factor rate will help ARC control its electric bill, provided that ARC can provide load control similar to what is currently required.

377. If ARC provides load control similar to its current requirement, its rate will increase by 9.32%.

378. The initially proposed Primary General Service rate increase was 12.75%, so the ARC increase is less than the increase applicable to similar C&I customers at primary voltage.

Substation Leases

379. It is unnecessary to require SPS to modify the way it leases substations to customers who take service at transmission voltage because there has been no showing that there is a problem among SPS customers with the current approach.

380. Staff's recommendation to amend SPS's LGS-T tariff and the Electric Service Agreements between SPS and its LGS-T customers is not reasonable given the significant changes required to implement the recommendation.

381. SPS's substation leasing practices are proper and reasonable.

Miscellaneous Preliminary Order Cost Allocation and Rate Design Issues

382. SPS has no existing rate riders that should be modified or terminated, and SPS has proposed no rate riders in this case.

383. The following tariff revisions proposed by SPS are uncontested, are reasonable, and are approved:

- Establishment of experimental TOU rates for customers in the Residential Service, Small General Service, Secondary General Service, Primary General Service, Small Municipal and School Service, Large Municipal Service, and Large School Service classes;

- Establishment of Tariff Sheet No. IV-206, which is a Low Load Factor tariff, for the Secondary General Service and Primary General Service classes;

- Amendment of Tariff Sheet No. IV-56 to delete Chase Bank as a customer listed under the tariff. The outdoor lighting for Chase Bank has been updated, and it no longer requires a service agreement because the lighting can be billed under other generally applicable lighting rates;

- Elimination of Tariff Sheet No. IV-58 because Cal Farley's Boys Ranch no longer takes service under the tariff;

- Revision of Tariff Sheet No. IV-99 to correct references to the company listed in the tariff from "Degussa" to "Orion Engineered Carbons" to reflect the customer's change in name;

- Revision of the Distributed Generation Interconnection tariff to avoid duplication of information. Presently, both the Distributed Generation Interconnection tariff (IV-159) and the Secondary Standby Service tariff (IV-180) provide rates for Secondary Standby Service. SPS proposes to remove the rate information from the Distributed Generation Interconnection tariff and to refer to the Secondary Standby Service tariff for rate information. SPS is also proposing to delete a reference to a discount for service at primary voltage because SPS also offers Primary Standby Service;

- Revision of the applicability section of Small Municipal and School Service and Large School Service tariffs to add language clarifying that the tariffs apply only to K-12 schools, whether public or private;

- Revision of Tariff Sheet Nos. IV-179, IV-180, IV-181, and IV-183 to clarify that, for customers that have power factor metering, the power factor charge will apply. SPS further proposes the addition of a power factor provision to applicable customers with 200 kW loads or greater; and

- Revision of Tariff Sheet Nos. IV-18, IV-108, IV-173, IV-175, IV-179, IV-180, IV-181, IV-182, and IV-183 to change billing for power factors below 90% from kVAR-based to kW-based. The 90% power factor allows a 5% grace level before the revised power factor charges are applied. The revised power factor charges ensure a ratio of 95% power factor to metered power factor multiplied by metered kW and the applicable kW charge.

Procedures and Model for Number Runs and Compliance Tariff

384. The Management Applications Consultants, Inc. is a reasonable tool to use for allocating costs among classes.

B. Conclusions of Law

1. SPS is a "public utility" as that term is defined in PURA § 11.004(1) and an "electric utility" as that term is defined in PURA § 31.002(6).

2. The Commission has jurisdiction over this matter under PURA §§ 14.001, 36.001-36.111, 36.203-36.205, 36.209, and 36.210, and 16 TAC §§ 25.231, 25.238, 25.239, 25.243, and 25.245.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket pursuant to PURA § 14.053 and Tex. Gov't Code § 2003.049.

4. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Tex. Gov't Code chapter 2001.

5. SPS provided notice of its application in accordance with PURA § 36.103 and 16 TAC §§ 22.51(a) and 25.235(b).

6. Pursuant to PURA § 33.001, each municipality in SPS's service area that has not ceded jurisdiction to the Commission has jurisdiction over SPS's application.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. SPS has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, SPS's overall revenues approved in this proceeding permit SPS a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to SPS in providing service.

11. SPS's proposed post-test year adjustments to rate base violate 16 TAC § 25.231(c)(2)(F)(i)(II) and (ii)(I), and SPS did not show good cause to make an exception to those rule requirements.

12. The ADIT adjustments approved in this proceeding are consistent with PURA § 36.059 and 16 TAC § 25.231(c)(2)(C)(i).

13. Including the cash working capital approved in this proceedings in SPS's rate base is consistent with 16 TAC § 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

14. The return on equity and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

15. 16 TAC § 25.231(b) provides that in computing a utility's reasonable and necessary operating expenses, the Commission should consider historical test year expenses as adjusted for known and measurable changes.

16. PURA § 36.065(b) allows a utility to establish a reserve account to record the difference between the amount of pension and OPEB expense approved in the utility's last general rate case and the annual amount of pension and OPEB expense that the utility actually bears.

17. 16 TAC § 25.231(b)(1)(b) provides that depreciation expense based on original cost and computed on a straight-line basis as approved by the Commission shall be used, but other methods may be used when the Commission determines that such depreciation methodology is a more reasonable means of recovering the costs of plant.

18. The reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

19. The affiliate expenses approved in this proceeding and included in SPS's rates meet the affiliate payment standards articulated in PURA §§ 36.051 and 36.058 and in *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W. 2d 783 (Tex. App.—Austin 1984, no writ).

20. Crediting REC sales revenues through fuel costs is not allowed under 16 TAC § 25.236, and SPS did not demonstrate good cause to make an exception to that rule.

C. Ordering Paragraphs

1. The proposal for decision is adopted to the extent consistent with this Order.

2. SPS's application is granted to the extent consistent with this Order.

3. SPS is authorized to file an application to implement a surcharge to recover the revenue it would have received for service rendered on and after June 11, 2015, through the date the rates set in this case take effect.

4. SPS shall file in Tariff Control No. _____, *Compliance Tariff Pursuant to Final Order in Docket No. 43695 (Application of Southwestern Public Service Company for Authority to Change Rates*) tariffs consistent with this Order within 20 days of the date of this Order. No later than 10 days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days

after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

5. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, SPS shall file proposed revisions of those sheets in accordance with the Commission's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

6. Copies of all tariff-related filings shall be served on all parties of record.

7. SPS shall investigate (including work with affiliates regarding their charges) and detail in its next rate case the reasons for the substantial increases in its A&G and distribution O&M expenses, steps being taken to reduce them, and the timing and cost impact of those steps.

8. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED October 12, 2015

ELIZABETH DREWS
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

LILO D. POMERLEAU
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

CASEY A. BELL
ADMINISTRATIVE LAW JUDGE
STATE OFFICE OF ADMINISTRATIVE HEARINGS

The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 15-155 September 30, 2016

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on November 6, 2015, to be effective December 1, 2015.

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TABLE OF CONTENTS

I. INTRODUCTION

On November 6, 2015, Massachusetts Electric Company ("MECo") and Nantucket Electric Company ("Nantucket Electric"), together doing business as National Grid ("National Grid" or "Company") filed a petition with the Department of Public Utilities ("Department") for an increase in its base distribution rates for electric customers. National Grid was last granted an increase in electric distribution rates in 2009 in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39 (2009). The Department docketed the instant matter as D.P.U. 15-155, and suspended the effective date of the proposed rate increase until October 1, 2016, to investigate the propriety of the Company's petition.

MECo and Nantucket Electric are regulated investor-owned public utilities incorporated in Massachusetts (Exh. NG-MLR-1, at 23). Both companies operate as wholly owned subsidiaries of National Grid USA, which is an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales (Exh. NG-MLR-1, at 23).[1] National Grid is engaged in the retail distribution and sale of electricity across a Massachusetts service territory that serves approximately 1.3 million customers in 172 cities and towns (Exh. NG-MLR-1, at 23).

In the instant filing, the Company seeks a combined increase in base distribution rate revenues of $201.9 million (Exh. NG-RRP-2, at 1 (Rev. 3)).[2] The Company contends that its

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1 National Grid USA also owns affiliated electric and gas distribution companies operating in Rhode Island and New York, while National Grid plc owns and operates electricity transmission, gas transmission and distribution networks in the United Kingdom (Exh. NG-MLR-1, at 23).

2 On September 12, 2016, the Company advised the Department of the need to file amended Annual Returns for calendar years 2014 and 2015 to correct a purported error

petition also includes a $68.7 million decrease in revenues recovered in charges outside of base rates (Exh. NG-RRP-2, at 1 (Rev. 3)). Thus, the Company claims that its petition requests a net increase in annual delivery revenues of $133.2 million, or an approximately 20.3 percent increase in current annual delivery revenues (Exh. NG-RRP-2, at 1 (Rev. 3)).

As part of this filing, National Grid also seeks to continue, with several proposed modifications, its capital investment recovery mechanism ("CapEx"), which was approved in D.P.U. 09-39 and permits the Company to recover the revenue requirement associated with incremental capital investments. Further, National Grid seeks to continue, with several proposed modifications, its storm contingency fund, which originally was approved in New England Electric System, D.T.E. 99-47 (2000) and permits the Company to recover costs associated with certain storm-restoration activities. In addition, the Company offers several rate design-related proposals and a tariff intended to recover incremental property tax expense. The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015 (Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).

II. PROCEDURAL HISTORY

On November 16, 2015, the Attorney General of the Commonwealth of Massachusetts filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). On December 1, 2015, the

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regarding the recording of plant in service for fiscal years ending March 31, 2013 through 2016 (Cover Letter at 1, dated September 12, 2016). According to National Grid, now that the costs are correctly recorded, the Company will experience a net increase to operating expense of approximately $200,000 annually that will not be reflected in new distribution rates set in this proceeding (Cover Letter at 1). The Company does not seek to incorporate into the record in the instant case these amended Annual Returns, or the corrected recording of plant and expenses (Cover Letter at 1). Nevertheless, the Department finds that the Company's filing is extra-record material to which we give no probative weight. The Department will not consider these materials in evaluating the Company's instant petition for a base rate increase.

Department granted full party status to the Department of Energy Resources ("DOER") and the Low-Income Weatherization and Fuel Assistance Program Network ("Low Income Network"), limited participant status to PowerOptions, Inc., and joint limited participant status to NSTAR Electric Company, NSTAR Gas Company and Western Massachusetts Electric Company, together doing business as Eversource Energy. On December 10, 2015, the Department granted limited participant status to Solar Energy Industries Association. The following day, the Department granted limited participant status separately to The Berkshire Gas Company, and jointly to The Energy Consortium ("TEC") and Associated Industries of Massachusetts ("AIM"). On December 14, 2015, the Department granted limited participant status to The Alliance for Solar Choice. On December 17, 2015, the Department granted limited participant status to Brightergy, LLC.

On January 14, 2016, the Department granted limited intervenor status to Acadia Center; Vote Solar; Direct Energy Business, LLC, Direct Energy Services, LLC, and Astrum Solar, Inc. d/b/a Direct Energy Solar (collectively as "Direct Solar"); Energy Freedom Coalition of America, LLC ("EFCA"); and Northeast Clean Energy Council, Inc. ("NECEC"). See Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, Interlocutory Order (January 14, 2016).

Pursuant to notice duly issued, the Department held five public hearings in the Company's service territory: (1) in Brockton on March 15, 2016; (2) in Nantucket on March 21, 2016; (3) in Worcester on March 30, 2016; (4) in Great Barrington on April 4, 2016; and (5) in Lawrence on April 6, 2016. The Department also received written comments from public officials and several National Grid ratepayers.

The Department held 15 days of evidentiary hearings from May 2, 2016, through May 26, 2016. In support of the Company's filing, the following witnesses, all of whom are employed by National Grid USA Service Company, Inc. ("NGSC"), provided testimony: (1) Marcy L. Reed, president – Massachusetts; (2) Michael D. Laflamme, vice president, regulation and pricing – New England; (3) Margaret H. Kinsman, director of revenue requirements group – New England; (4) Maureen P. Heaphy, vice president of compensation, benefits and pensions; (5) James H. Patterson, Jr., director of network strategy – New England; (6) Stefan Nagy, analyst, program strategy; (7) John E. Walter, principal engineer, outdoor lighting and attachments group; (8) Jeanne A. Lloyd, principal program manager (electric pricing), regulation and pricing group – New England; (9) Peter T. Zschokke, director, regulatory strategy; (10) Scott M. McCabe, manager (electric pricing), regulation and pricing group – New England; (11) Timothy Roughan, director, energy/environmental policy; (12) Daniel J. DeMauro, Jr., director, IS Regulatory Compliance; (13) David H. Campbell, vice president, corporate finance; (14) Christopher P. Murphy, acting vice president, chief information officer; (15) Ryan Moe, senior specialist for vegetation strategy; (16) Daniel Bunszell, vice president, electric operations – New England; (17) Gladys Sarji, customer satisfaction and regulatory compliance; (18) Nancy Concemi, director, New England call center; and (19) John B. Currie, director, revenue and regulation – New England. In addition to NGSC personnel, the following outside consultants provided testimony on behalf of National Grid: (1) Robert B. Hevert, managing partner, Sussex Economic Advisors; (2) Ronald E. White, president, Foster Associates Consultants, LLC; (3) Howard Gorman, president, HSG Group, Inc.; and (4) Wayne S. Watkins, Pro Unlimited, Inc.

The Attorney General sponsored the testimony of the following witnesses:[3] (1) J. Randall Woolridge, Ph.D., professor of finance, Pennsylvania State University; (2) David J. Effron, consultant, Berkshire Consulting Services; (3) Donna Ramas, principal, Ramas Regulatory Consulting, LLC; (4) Timothy Newhard, analyst, Attorney General's Office of Ratepayer Advocacy; (5) Kyle Connors, analyst, Attorney General's Office of Ratepayer Advocacy; (6) Daniel O'Neill, president, O'Neill Management Consulting; (7) Charles Fijnvandraat, principal, Fijnvandraat Consulting Group; (8) Scott Rubin, consultant; and (9) William Dunkel, principal, William Dunkel and Associates.

The Low Income Network sponsored the testimony of John G. Howat, senior policy analyst, National Consumer Law Center, and Marina Levy, research assistant, National Consumer Law Center. Acadia Center sponsored the testimony of Abigail Anthony, Ph.D., director, grid modernization and utility reform, Acadia Center. Direct Energy sponsored the testimony of Frank Lacey, principal, Electric Advisors Consulting. EFCA sponsored the testimony of Tim Woolf, vice president, Synapse Energy Economics, Inc., and Melissa Whited, senior associate, Synapse Energy Economics, Inc. NECEC sponsored the testimony of R. Thomas Beach, principal consultant, Crossborder Energy. Finally, Vote Solar sponsored the testimony of Nathan Phelps, program manager, distributed generation regulatory policy, Vote Solar.

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3 On December 15, 2015, the Department approved the Attorney General's retention of experts and consultants at a cost of $250,000, pursuant to G.L. c. 12, § 11E(b). See D.P.U. 15-155, Order on Attorney General Retention of Experts and Consultants (2015).

On June 17, 2016, the Department received initial briefs/comments from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, NSTAR Electric Company and Western Massachusetts Electric Company (collectively as "Eversource") and Vote Solar. National Grid submitted its initial brief on July 1, 2016.

On July 18, 2016, the Department received reply briefs from the Attorney General, DOER, the Low Income Network, Acadia Center, Direct Energy, EFCA, NECEC, Vote Solar, PowerOptions, Inc., and, collectively, from TEC and AIM. The Company submitted its reply brief on July 25, 2016. The evidentiary record consists of more than 3800 exhibits and responses to 97 record requests.

III. NATIONAL GRID'S USE OF A SPLIT TEST YEAR

A. Introduction

The cost of service component of the Company's filing is based on a test year of July 1, 2014, through June 30, 2015, a non-calendar or "split" test year (see Exhs. NG-MLR-1, at 3; NG-RRP-1, at 6).[4] Non-calendar test years have, on occasion, been accepted by the Department – most recently for water companies. See, e.g., Plymouth Water Company, D.P.U. 14-120, at 16 (2015); Milford Water Company, D.P.U. 12-86, at 1 (2013); Colonial Water Company, D.P.U. 11-20 (2011); Massachusetts-American Water Company, D.T.E. 00-105 (2001). As discussed in further detail below, the Department recently expressed its strong preference for a calendar year test year and noted that any company that seeks to rely on a split test year faces a

4 A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. NSTAR Gas Company, D.P.U. 14-150, at 45, n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar test year or a split test year, comprises a period of twelve consecutive calendar months.

high burden to demonstrate as a threshold matter that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period.
D.P.U. 14-120, at 16 & n.11.

In support of its split test year filing, National Grid retained the independent accounting firm of PricewaterhouseCoopers, LLC ("PwC") to review the Company's operations and verify the accuracy of its non-calendar year test year financial data (Exhs. NG-RRP-1, at 6-7; NG-RRP-3).[5] PwC's review was performed under the attestation standards of the American Institute of Certified Public Accountants (Exh. NG-RRP-3, at 4). On October 30, 2015, PwC issued a report ("PwC Report") of its findings, which the Company submitted as part of the initial filing in this case (Exh. NG-RRP-3).

The scope of PwC's examination encompassed transactions recorded by the Company and NGSC (Exh. NG-RRP-3, at 4). PwC reviewed selected transactions that occurred during the test year in order to form an opinion on the accuracy of those transactions (Exh. NG-RRP-3, at 4). The transactions reviewed included vendor costs, labor costs and employee expense costs (Exh. NG-RRP-3, at 5).[6] PwC also examined general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 5). The PwC Report describes the sampling method used for each cost area (Exh. NG-RRP-3, at 5). The PwC Report also

5 The Company does not seek inclusion of the costs incurred for this review in this proceeding (Exhs. DPU-4-9; DPU-4-10; AG-15-1, at 2 (corrected)).

6 For example, PWC performed the following tests with respect to vendor costs: (1) compare the cost recorded in the Company's ledger to the underlying vendor support such as an invoice or similar document; (2) review the underlying vendor information for the details of the services performed and identify whether services relate to the entity to which they were charged; and (3) review the underlying vendor information for the details of the services performed and identify whether the services were performed in support of the capital program (Exh. NG-RRP-3, at 6).

describes the testing procedures performed to ensure that costs were incurred, accurately calculated to reflect the underlying transaction, allocated to the correct operating company (where applicable), properly allocated among capital and expense (where applicable), and consistent with Company policy (Exh. NG-RRP-3, at 6). PwC examined, on a test basis, evidence supporting management's assertions regarding costs and performed other such procedures as PwC considered necessary under the circumstances (Exh. NG-RRP-3, at 27, 46). PwC concluded that the selected costs, in all material respects, were accurate (Exh. NG-RRP-3, at 27, 46).

B. Positions of the Parties

1. Attorney General

The Attorney General submits that because the Department establishes a utility's cost of service using test year data, and that the resulting distribution rates may be in effect for five years or more, a utility's test year financial information must be "accurate, verifiable, and verified" (Attorney General Brief at 8). Further, the Attorney General contends that the use of a spilt test year, rather than a calendar year, is problematic because it does not conform to the annual reporting periods or requirements set forth by the Department, the Federal Energy Regulatory Commission ("FERC"), and the Securities and Exchange Commission (Attorney General Brief at 8). She asserts that in the instant case, because National Grid chose to file its base rate case using a split test year, the Company must comply with the directives set forth in D.P.U. 14-120 to ensure that the record contains reliable and verifiable financial information (Attorney General Brief at 9-10).

In this regard, the Attorney General argues that National Grid failed to comply with the split test year filing requirements set forth in D.P.U. 14-120, because the Company: (1) failed to show that its test year account balances tie back to its Annual Returns to the Department;[7] and (2) failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9).[8] With respect to the first point, the Attorney General contends that the Company's requested rate increase is based on unverified worksheets (Attorney General Brief at 9). Further, the Attorney General claims that the PwC Report does not support the notion that the Company's account balances tie back to the Annual Return (Attorney General Reply Brief at 5). The Attorney General asserts that because a calendar year test year ties back to a company's Annual Return, the same level of verification is required for a split test year filing (Attorney General Reply Brief at 5). According to the Attorney General, the Department cannot on its own verify the accuracy of the Company's test year data and instead an

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7 Electric distribution companies, such as National Grid, must file an Annual Return with the Department annually on or before March 31. G.L. c. 164, § 83; 220 C.M.R. § 79.00, Introduction. The Annual Return includes the FERC Form 1 prescribed by FERC. 220 C.M.R. § 79.04(1). The FERC Form 1 presents financial and other operating data based on a calendar year ending December 31. 18 C.F.R. § 141.1(b)(2). The use of a calendar test year ensures that test year amounts tie back to the amounts included in the Annual Returns, and offers a level of assurance that the amounts have been properly recorded and are generally available for review. D.P.U. 14-120, at 11.

8 As explained by the American Institute of Certified Public Accountants ("AICPA"), an unqualified opinion presented in a report on the audit of financial statements states that the financial statements present fairly, in all material respects, the financial position, results of operations, and cash flows of the entity in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508.10, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf.

unqualified opinion letter is necessary for such verification (Attorney General Reply Brief at 3, 5, citing D.P.U. 14-120 at 11 & 16, n.11).

With respect to the audit requirement, the Attorney General argues that the Company's financial records were simply reviewed by an independent third party (i.e., PwC) and not audited as required by the Department in D.P.U. 14-120 (Attorney General Brief at 9, n.5, citing Exh. NG-RRP-1, at 6). In this regard, the Attorney General argues that PwC's review and subsequent report does not equate to an unqualified opinion letter from an independent auditor attesting to the accuracy of the financial information used to develop the cost of service in this case (Attorney General Brief at 9; Attorney General Reply Brief at 5). Further, the Attorney General rejects any notion that PwC's review of the Company's financial information was more thorough than a financial audit (Attorney General Reply Brief at 5). Thus, the Attorney General asserts that the Company has failed to meet its burden to provide an adequate record sufficient to enable the Department to conduct a meaningful review (Attorney General Reply Brief at 3, citing Town of Hingham v. Dep't. of Telecom. and Energy, 433 Mass. 198, 213-214 (2001)).[9]

Based on the above considerations, the Attorney General asserts that the Department should consider as a factor in setting National Grid's allowed rate of return, the Company's

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9 In particular, the Attorney General identifies three areas where she argues that a financial audit could have prevented the submission of inaccurate data to the Department: (1) the Company's purported overstatement of its depreciation expense caused by the inclusion of $100 million in plant retirements in the test year-end plant balance; (2) the Company's purported overstatement of net plant due to the failure to record $26 million in salvage; and (3) the Company's purported omission of certain project reports relating to plant additions (Attorney General Reply Brief at 4, citing Exhs. AG-18-19; AG-30-1, Att.; RR-AG-28). These issues are discussed in Sections III and VIII.E below. According to the Attorney General, a proper audit likely would have revealed additional significant inaccuracies that would be highly relevant to this proceeding (Attorney General Reply Brief at 4).

failure to meet the directives of D.P.U. 14-120 in using a split test year. Specifically, the Attorney General recommends that the Department should set the Company's allowed return on equity ("ROE") at the lowest end of the range of reasonableness (Attorney General Brief at 10, citing Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 231 (2002); Attorney General Reply Brief at 6).

2. Company

National Grid argues that it prepared its filing in compliance with the directives set forth in D.P.U. 14-120 (Company Brief at 9, citing Exh. NG-RRP-1, at 6-7). First, the Company argues that it developed financial statements that directly tie to the Company's 2014 Annual Return and to data submitted to FERC on FERC Forms 1 and 3-Q,[10] which are signed and sworn to by an officer of the Company (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). More specifically, the Company argues that these financial statements incorporate data submitted to FERC on FERC Form 1 for the calendar year 2014, which comprise the first six months of the test year, and FERC Form 3-Q for the year to date periods ending June 30, 2014 and June 30, 2015 (Company Brief at 9, 14, citing Exhs. NG-RRP-1, at 6-7; AG-1-2; WP-NG-RRP-1(a)(b)(c); Tr. 9, at 1395-1400; RR-AG-29; Company Reply Brief at 15). The Company contends that these financial statements provide the Department with a direct tie to data included in the Company's 2014 Annual Return and allow for a meaningful year-to-year comparison of twelve months of data to the annual data provided in the Annual Returns (Company Brief at 9,

10 FERC Form 3-Q presents financial and operating data on a calendar quarter basis, with a FERC Form 3-Q filed for each calendar quarter. 18 C.F.R. § 260.300. The Department does not require companies to submit their FERC Form 3-Q.

citing Exh. NG-RRP-1, at 6-7). The Company asserts that the Attorney General has not raised any specific instances of how these financial statements fail to tie back to the 2014 Annual Return, FERC Form 1 or FERC Form 3-Q (Company Brief at 14).

Second, National Grid argues that the PwC Report provides a solid foundation for the Department to review and analyze the Company's financial records used to develop the cost of service because it is an extensive third-party review of the test year data designed to verify data integrity and accuracy (Company Brief at 9, 15, citing Exhs. NG-RRP-1, at 6-11; NG-RRP-3). According to National Grid, there is no requirement set forth in D.P.U. 14-120 that the test year data is to be included in a routine annual audit or that the Company needs to obtain an unqualified opinion (Company Reply Brief at 13). Instead, the Company argues that D.P.U. 14-120 requires a showing that the test year amounts have been "properly audited," and that the PwC Report is sufficient to meet that requirement (Company Reply Brief at 13). In this regard, the Company asserts that PwC's review: (1) was performed under appropriate industry standards; and (2) was more thorough than the Company's annual financial audit conducted by PwC, particularly in relation to the specific financial data forming the cost of service in this proceeding (Company Brief at 10-11, 15, citing Exhs. NG-RRP-1, at 6-7; NG-RRP-3, at 4-5; AG-15-1, at 8, 9 (Corrected); Tr. 9, at 1399-1400, 1522-1523; Company Reply Brief at 13).

According to the Company, the PwC Report shows that: (1) the costs charged to the operating companies from the service companies were recorded accurately; (2) on a net basis, the costs were allocated appropriately to the various operating companies, consistent with the appropriate cost allocation manual; (3) the findings associated with the cost data provided in the scope of testing were not material to the service companies involved or to any one business unit;

and (4) there were no other pertinent facts identified during the review process indicating that the cost should be allocated differently (Company Brief at 12, citing Exhs. NG-RRP-3; AG-15-2, at 10 (Supp.)). The Company asserts that there is no evidence to suggest that a different type of audit would have produced different results (Company Reply Brief at 13-14).

Based on the foregoing, National Grid argues that the PwC Report substantiates the Company's use of a split test year in this proceeding and meets the threshold requirements set forth by the Department in D.P.U. 14-120 (Company Brief at 13). Thus, the Company asserts that the Department should find that the Company has met its burden with respect to using a split test year, and it should reject the Attorney General's recommendation that an adjustment to the allowed rate of return is warranted (Company Brief at 13, 16; Company Reply Brief at 15-16).

C. Analysis and Findings

1. Introduction

It is well-established Department precedent that base rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45; D.P.U. 14-120, at 12, 16; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone and Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). See also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to G.L. c. 164, § 94 ("§ 94"), the Department examines a test year on the basis that the revenue, expense, and rate base figures during that period, adjusted for known and measurable changes, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. D.P.U. 14-120, at 9; see Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 146 (2016); citing D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45, n. 26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978).

As noted above, the Department has expressed strong preference for a test year cost of service based on a calendar year as opposed to a split test year. D.P.U. 14-120, at 12, 16; see also D.P.U. 14-150, at 45, n.26. Although the Department has, on occasion, accepted a non-calendar test year, see D.P.U. 14-120, at 10, 16; D.P.U. 12-86, at 1; D.P.U. 11-20; D.T.E. 00-105, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; see AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test year amounts associated with a split test year will not tie back to amounts included in the Annual Returns submitted to the Department, which are prepared on a calendar-year basis. D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test year may create an improper incentive for utilities to book expenses into a certain time period for purposes of creating an inflated test year expense. D.P.U. 14-120, at 11. Another complication associated with use of split test years involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate setting process, may result in distorted measurement of net operations. D.P.U. 14-120, at 11; see The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

It also is well established that the burden is with a company to satisfy the Department that the company's proposal will result in just and reasonable rates. D.P.U. 14-120, at 11-12; Boston Gas Company, D.T.E. 03-40, at 52, n.31 (2003), citing The Berkshire Gas Company, D.T.E. 01-56-A at 16 (2002); New England Gas Company, D.P.U. 10-114, at 22 (2011); Boston Gas Company, D.P.U. 93-60, at 212 (1993); Blackstone Gas Company, D.P.U. 19579, at 2-3 (1978).[11] Therefore, given the importance of the concerns discussed above and their significance for ratepayers, the Department affirms its very clear preference to use an historic calendar year test year to establish rates. D.P.U. 14-120, at 11-12.

As we noted in D.P.U. 14-120, at 12, any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and

11 That the burden of proof is always with those who take the affirmative in pleading is a long-held tenet in Massachusetts jurisprudence. Phelps v. Hartwell, 1 Mass. 71, 73 (1804).

reasonable. Specifically, any company that seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976). Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

> (1) of how its test year account balances tie back to the account balances as reported in the Annual Returns;
>
> (2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;
>
> (3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and
>
> (4) that the company has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances.

D.P.U. 14-120, at 16 n.11.

2. Discussion

As noted above, the Attorney General's challenge to the propriety of National Grid's reliance on a split test year rests on two main arguments: (1) that the Company failed to show that its test year account balances tie back to the Annual Return to the Department; and (2) that the Company failed to provide an audit of the test year amounts that resulted in an unqualified opinion letter (Attorney General Brief at 9). However, we will address all four split test year threshold requirements set forth in D.P.U. 14-120.

First, the Company provided audited financial statements for the fiscal year ending March 31, 2015 (Exh AG-1-2, Att. 3 (3g) & (4g)).[12] While the Company's audited financial statements are not prepared using the same twelve-month period as the test year, the Department finds such statements helpful in ensuring that the Company's test year account balances have been verified, especially given that nine of the twelve months were the subject of the audit of the fiscal year ended March 31, 2015 (Exh. AG-1-2, Att. 3 (3g), (4g); Tr. 9, at 1397). The Company also provided the FERC Form 1s for the calendar years ending December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 4 (1f), (2f); RR-AG-29, Atts. 1, 3). Further, the Company provided its Annual Returns to the Department for calendar years ended December 31, 2014 and December 31, 2015 (Exh. AG-1-2, Atts. 7 (1f), (2f); RR-AG-29, Atts. 2, 4). In addition, the Company provided FERC Form 1 financial statements containing financial information for the twelve months ended June 30, 2015 (Exhs. NG-RRP-1 at 6; WP-NG-RRP-1(a), (b), (c)). Based on our review of this information, we find that it is possible, though not easily discernible, to tie the Company's test year account balances back to the account balances as reported in the Annual Returns. See D.P.U. 14-120, at 16 n.11.

Next, the Company provided audited financial statements for the fiscal years ended 2009 through 2014 (Exh. AG-1-2, Atts. 3 (3a) through (4g)). In addition, the Company provided the

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12 A financial audit is an examination of historical financial statements performed in accordance with generally accepted auditing standards, with a report issued on the results stating an opinion whether the financial statements present the audited entity's financial position, results of operations, and cash flows in conformity with generally accepted accounting principles. AICPA Professional Standards, Reports on Audited Financial Statements, AU § 508, n.1, §§ 508.07.08, located at http://www.aicpa.org/Research/Standards/AuditAttest/DownloadableDocuments/AU-00508.pdf; see also D.P.U. 14-120, at 15.

FERC Form 1s for calendar years ending December 31, 2009 and December 31, 2013 (Exh. AG-1-2, Atts. 4 (1a) through (2f)). We conclude that this information, when reviewed in conjunction with the test year data and the PwC Report (as discussed in greater detail below), allows for a meaningful review of year-to-year changes in expense levels in order to determine whether the Company's test year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability. See D.P.U. 14-120, at 16 n.11.

Further, we find that the test year amounts have been properly audited and are available for review. In particular, we are not persuaded by the Attorney General's argument that the Company's financial statements are unreliable because they lack verification through an unqualified opinion letter. While the PwC Report does not represent an unqualified opinion letter, we find that it does provide an independent and extensive review of the Company's test year cost of service data that is sufficient to make the D.P.U. 14-120 threshold showing. As noted, the record contains several of the Company's annual financial audits (Exh. AG-1-2, Att. 3 (3g) & (4g); Tr. 9 at 1397). As discussed below, in this instance PwC's review was, in a number of ways, likely more extensive than the scope of these financial audits.

The record shows that PwC performed an extensive review of over 4,500 individual invoice transactions relevant to the Company's cost of service in this case, including vendor costs, labor costs, employee expense costs, and general ledger journal entries relating to operating expense general ledger accounts (Exh. NG-RRP-3, at 4-5; Tr. 9, at 1522-1523). Thus, PwC's review encompassed a wide range of expense activity on a transactional level, as opposed to a review of a smaller sample population of transactions, which is typically done in a financial audit (Exh. NG-RRP-1, at 8-9; Tr. 9, at 1399-1400).

For each cost area, the PwC Report clearly describes the methods used to select which transactions were reviewed (Exh. NG-RRP-3, at 5). Further, the PwC Report describes the extensive testing procedures performed to verify the propriety of costs incurred by the Company in the split test year (Exhs. NG-RRP-3, at 6; NG-RRP-1, at 7-8). The record shows that for each of the charges it reviewed, PwC examined relevant supporting documentation, such as invoices, expense reports, receipts, time sheets and other documents (Exhs. NG-RRP-3, at 6; AG-15-1, at 8 (corrected)). Further, for each charge, PwC confirmed that it was: (1) incurred during the split test year; (2) accurate; (3) properly allocated to the correct company or companies (where applicable) and to expense or capital (where applicable); (4) properly allocated in accordance with National Grid USA's Cost Allocation Policies and Procedures Manual ("CAM"); and (5) not accounted for as below-the-line for ratemaking purposes (Exhs. NG-RRP-1, at 7-8; NG-RRP-3, at 6, 30; AG-15-1, at 8 (corrected)). Thus, PwC's review was likely more extensive for ratemaking purposes than a financial audit, which tends to focus on whether the Company has properly maintained its financial records consistent with accounting requirements. See D.P.U. 14-120, at 15. If PwC found that there was inadequate support for a particular charge or if it had questions regarding a particular charge, it undertook a further examination of the charge, including requesting additional documentation to support the charge and, frequently, following up with the business process owner to understand the allocation related to a particular charge (Exh. NG-RRP-1, at 8). In instances where the Company could not provide sufficient support for the charge or a clear explanation of the charge allocation, PwC flagged the charge as a proposed adjustment or considered whether a different bill pool or direct charge would have been more appropriate to use as a basis for cost allocation (Exh. NG-RRP-1, at 8). Based on the quality and comprehensiveness of PwC's review, we find that there is a sufficient basis to conclude that the Company's test year amounts have been properly "audited" in order to satisfy the split test year threshold requirement as set forth in D.P.U. 14-120. D.P.U. 14-120, at 16 n.11.[13]

Finally, PwC reviewed beginning and end-of-year accruals in order to review the allocation of costs among monthly periods during the split test year (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). In particular, PwC identified all vendor cost invoices that had service dates prior to the beginning of the test year and compared the amount recognized as a cost in the test year to the amount accrued at the beginning of the test year and reversed during the test year, in order to test the elimination of out-of-period charges in the test year data (Exh. NG-RRP-3, at 14, 24). PwC then reviewed accruals recorded at the end of the test year and compared the amounts of supporting calculations (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 14, 24). Further, PwC reviewed a number of invoices received after the test year to determine if those invoices related to services performed in the test year and, for those invoices that did, compared the

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[13] In light of this finding, we need not address the Attorney General's argument that the Department cannot, on its own, verify the Company's test year data. Further, we are not persuaded by the Attorney General's argument that use of a calendar year test year and an unqualified opinion letter would have prevented the Company's purported overstatement of depreciation and net plant, or its alleged failure to file certain project reports at the outset of the case (Attorney General Reply Brief at 4). While we expect National Grid to present a filing that is as complete and accurate as possible, these concerns are not sufficient to call into question the reviewability of the Company's entire rate request. Instead, the Department will determine the appropriate ratemaking treatment of these items, under the circumstances identified by the Attorney General, in the relevant sections of this Order.

invoice to the accruals at the end of the test year to determine an appropriate adjustment to test year costs (Exh. NG-RRP-1, at 9).[14] Based on these findings, we conclude that through the PwC Report, the Company has shown that it has properly recognized accruals booked to reserve accounts, including any end of period reconciliations of those account balances. D.P.U. 14-120, at 16 n.11.

3. Conclusion

Based on the above considerations, the Department finds that National Grid has satisfied the split test year threshold requirements set forth in D.P.U. 14-120 and has demonstrated by clear and convincing evidence that its financial data is reviewable and reliable and represents a full accounting of the Company's operations for the test year period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate National Grid's filing based on a test year for the twelve months ending June 30, 2015. Further, we decline to make any specific adjustment to the Company's ROE due to the use of a split test year, as recommended by the Attorney General. However, while we accept PwC's findings for purposes of determining the accuracy and reviewability of the financial information submitted by the Company in this case, we do not accept the PwC Report as a proxy for establishing the appropriate cost of service in this case. As we have noted in prior cases, while audited financial statements are of considerable assistance in the ratemaking process, an audit does not establish either the reasonableness per se of the reported costs or the ratemaking treatment to be accorded

14 For this aspect of its examination and verification process, PwC reported a net decrease to test year costs for the Company in the amount of $1,094,601 (Exhs. NG-RRP-1, at 9; NG-RRP-3, at 7, 24). The Company states that this amount was offset by findings in other elements of PwC's review (Exh. NG-RRP-1, at 9).

to such costs. D.P.U. 14-120, at 15; citing Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240, Introductory Letter (May 19, 1941); Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997). The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in the specific sections of this Order that follow.

Finally, we emphasis that our findings here are limited to the specific facts and circumstances of this case and in no way change the Department's clear preference for companies to use a calendar year test year as the norm. D.P.U. 14-120, at 16. We reiterate that any company that seeks to rely on a split test year must, at a minimum threshold level, make a prima facie showing by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 14-120, at 16; see D.P.U. 19579, at 2-4; D.P.U. 18571/18572, at 4-14. Failure to make such a robust showing will result in dismissal of the company's rate proceeding.

IV. REVENUE DECOUPLING MECHANISM

A. Introduction

In D.P.U. 07-50-A at 4-5, 32, 81-82, the Department directed each electric and gas distribution company to propose a full revenue decoupling mechanism ("RDM") in its future base distribution rate proceedings. The Department stated that the objective of revenue decoupling is the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts." D.P.U. 07-50-A at 4. The Department concluded that "a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources." D.P.U. 07-50-A at 31-32.

In directing electric distribution companies to adopt full revenue decoupling, the Department acknowledged that decoupling would remove the opportunity to earn additional revenue from growth in sales between base distribution rate proceedings and further acknowledged that such revenue typically funded, among other things, increased operation and maintenance ("O&M") expenses as well as system reliability and capital investment projects. D.P.U. 07-50-A at 48, 87. Accordingly, the Department stated that it would consider company-specific proposals that account for the effects of increased capital investments and inflation on target revenue. D.P.U. 07-50-A at 49-50.[15]

The Department approved the Company's revenue decoupling provision in its last base distribution rate proceeding. D.P.U. 09-39, at 61-92. National Grid's current revenue decoupling tariff provision includes two components that operate in concert: (1) a traditional RDM reconciliation with full revenue decoupling; and (2) the Company's CapEx mechanism (Exh. NG-PP-1, at 82-83). In the RDM reconciliation, the annual target revenue ("ATR") set in the Company's base distribution rate proceeding is adjusted by the cumulative CapEx cost recovery for the upcoming year (Exh. NG-PP-1, at 83). The adjusted ATR is reconciled against billed base distribution revenue and CapEx factor revenue (Exh. NG-PP-1, at 83). The Company is authorized to collect up to three percent of total revenues through the resulting revenue decoupling adjustment factors ("RDAFs") (Exh. DPU-18-21, Att. at 5 (M.D.P.U. No. 1289,

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15 See Section VII.B for a discussion of the Company's proposal regarding capital investments.

Sheet 4, § V)). Each year's ATR is greater than the prior year's ATR because the CapEx cost recovery cumulates year-over-year from additional capital investments (Exh. NG-PP-1, at 83). Additionally, the total amount that the Company seeks recovery of through the RDM will eventually reach and exceed the three-percent cap because National Grid measures the entire annual CapEx cost recovery against the three-percent cap, instead of the change in CapEx cost recovery from year-to-year (Exh. NG-PP-1, at 85-86). Moreover, the current revenue decoupling provision does not permit the Company to apply a revenue cap separately to its RDM reconciliation component and to its CapEx recovery component (Exh. NG-PP-1, at 85). Instead, the three-percent cap is compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86).

B. Company Proposal

The Company proposes to remove the CapEx cost recovery from the current revenue decoupling provision tariff and move this component to a separate tariff and operate it as an independent cost recovery mechanism (see Section V) (Exhs. NG-PP-1, at 81; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).[16] The Company proposes that the remaining components of the revenue decoupling provision will govern the operation of National Grid's traditional RDM reconciliation.

In particular, the Company proposes to continue the traditional RDM reconciliation component in its revenue decoupling provision, with updated target revenues set at the proposed base rate revenue requirement for each customer class and modifications to the revenue cap

[16] The Company proposes to apply a separate revenue cap to the independent CapEx recovery component (Exhs. NG-PP-1, at 81-82; NG-PP-23, at 176-182 (proposed M.D.P.U. Nos. 1277, 1278)).

(Exhs. NG-PP-1, at 81; NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). National Grid's current and proposed ATRs by rate class are shown in the following table:

Rate Class	Current ATR	Proposed ATR
Rate R-1/R-2	$306,532,557	$451,769,965
Rate R-4	$347,350	$599,269
Rate G-1	$97,267,709	$97,070,193
Rate G-2	$56,298,775	$91,441,732
Rate G-3	$106,895,246	$140,607,030
Street lighting	$20,525,360	$17,639,752
Total	$587,866,996	$799,127,941

(Exhs. NG-PP-23, at 181 (proposed M.D.P.U. No. 1278, at sheet 2); NG-PP-24, at 259; DPU-18-21, Att. at 4). National Grid proposes to submit annual RDM filings by January 15 to reconcile its actual revenues to the ATR pursuant to its revenue decoupling provision, with the RDAFs to take effect on March 1 (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

However, the Company proposes two modifications to the RDM cap: (1) the revenue that forms the basis for the RDM cap will reflect total revenue and include an adjustment for electric supply for those customers who took service from a competitive supplier during the year; and (2) a three-percent cap will be applied to both under- and over-recoveries of the RDM reconciliation between billed revenue and ATR (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23).

Finally, in the Company's 2015 annual RDM reconciliation filing, the Department directed National Grid to adjust its ATR, not its distribution revenues, to account for the sale of street lighting assets, and the Company amended its revenue decoupling provision tariff accordingly (see Exh. DPU-18-21, Att. (M.D.P.U. No. 1289)). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 14-136-A at 11 (January 21, 2016). The primary revision to the revenue decoupling provision tariff was the addition of the "Streetlight Sales Adjustment" definition (Exh. DPU-18-21, Att. at 3 (M.D.P.U. No. 1289, at sheet 2)).[17]

C. Positions of the Parties

National Grid argues that the proposed modifications to its revenue decoupling provision align it with the operation of RDMs in place for other distribution utilities (Company Brief at 164).[18] No other party addressed the Company's proposed modifications to the traditional RDM reconciliation on brief.

D. Analysis and Findings

In Section V.D below, the Department allowed the Company to continue the operation of its CapEx mechanism in a separate tariff, with modifications, including its separation from the revenue decoupling provision and operation as a distinct reconciling mechanism. Thus, in this section we will address the Company's remaining proposed revisions to its traditional RDM reconciliation component of its current revenue decoupling provision.

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17 According to the Company, "'Streetlight Sales Adjustment' shall mean the annual cumulative dollar adjustment to each year's ATR as a result of selling its streetlighting equipment pursuant to G.L. c. 164 § 34A subsequent to the effective date of new base distribution rates resulting from a general rate case. The Streetlight Sales Adjustment shall be a downward adjustment to each year's ATR and shall be calculated as the proceeds received by the Company from the sale of its streetlighting equipment multiplied by the avoided cost of no longer owning, operating, and maintaining such equipment, stated as a percentage, as determined by the Company's final streetlight revenue requirement. The Streetlight Sales Adjustment shall be set to zero and calculated for new streetlight sales effective with the subsequent implementation of new base distribution rates as provided for above. The Streetlight Sales Adjustment is pursuant to the Department's directive in D.P.U. 14-136-A" (Exh. DPU-18-21, Att. at 3).

18 The Company does not specify whether these utilities are gas or electric utilities (Exh. NG-PP-1, at 84). However, the Company states that gas utility targeted infrastructure replacement programs demonstrate similar language on the application of revenue caps (Exh. NG-PP-1, at 84).

The Department has determined that a RDM must be consistent with our precedent related to rate continuity, fairness, and earnings stability. Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50, at 12 (2007). The Department has found that the application of a revenue cap in the context of a RDM is consistent with this precedent. D.P.U. 14-150, at 20; Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 116 (2011). Moreover, the Department has previously stated that revenue decoupling adjustments should be large enough to avoid intergenerational inequity and unfairness in rates but small enough to preserve continuity in rates. Western Massachusetts Electric Company, D.P.U. 10-70, at 45 (2011); D.P.U. 09-39, at 87.

The Company proposes two modifications to the RDM cap. First, the Department evaluates the Company's proposal to include an adjustment for electric supply for those customers who took service from a competitive supplier during the year. We find that this proposed adjustment is consistent with decoupling mechanisms in use by other utilities. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 24. Therefore, the Department accepts the Company's proposal.

Next, we address the proposed three-percent cap to be applied to the RDM reconciliation between billed revenue and ATR. The Company proposes to cap the total RDM reconciliation (excluding CapEx cost recovery) at three-percent of total revenues, including an adjustment for electric supply for those customers who took service from a competitive supplier during the year, and to apply the three-percent cap to both under- and over-recoveries of the RDM reconciliation balance (Exhs. NG-PP-1, at 82; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3); DPU-18-23). In previously approving a three-percent cap in the Company's revenue decoupling provision (which included CapEx cost recovery), the Department stated that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render the three-percent cap inappropriate. D.P.U. 09-39, at 88. The Department expressed that it may review and modify such a cap, as necessary, over the course of the Company's revenue decoupling adjustment filings. D.P.U. 09-39, at 88.

Although the Company's three-percent cap is consistent with the revenue decoupling provision approved in its previous base distribution rate proceeding, the three-percent cap was applied to an RDM adjustment that previously included a RDM reconciliation balance with an adjustment for CapEx cost recovery. D.P.U. 09-39, at 87-88. The three-percent cap was compared to the total amount to be recovered by both the traditional RDM reconciliation component and the CapEx cost recovery component (Exh. NG-PP-1, at 86). However, given that we have approved the continuation of the CapEx mechanism as a separate mechanism from the revenue decoupling tariff provision (see Section V.D below), it is now more appropriate to set National Grid's cap on the annual revenue decoupling adjustment at one-percent cap of total revenue. We conclude that a one-percent cap based on total revenues ensures continuity, fairness, and earnings stability. Any amount above the one-percent cap will be deferred with interest calculated at the customer deposit rate until there is sufficient room under a future cap to recover the deferral balance (Exhs. NG-PP-1, at 84; NG-PP-23, at 182 (proposed M.D.P.U. No. 1278, at sheet 3)).

Additionally, the purpose of the one-percent cap is to protect customers from large revenue decoupling adjustments. D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. However, no such protection is necessary in the event of a decoupling adjustment credit.

D.P.U. 15-80/D.P.U. 15-81, at 24-25; D.P.U. 14-150, at 21. Accordingly, the Department declines to accept the Company's proposal to apply the revenue cap to over-recoveries of ATR, which would result in a credit to customers (see Exh. DPU-18-23). The Department finds that the one-percent revenue cap shall apply only to under-recoveries of ATR.

Based on the foregoing, the Department directs the Company to modify the language of its revenue decoupling provision tariff to include a revenue decoupling adjustment cap that is based on one-percent of total Company revenues from the previous calendar year. National Grid is also directed to include language in its revenue decoupling provision tariff that ensures that the revenue decoupling adjustment cap is applied only to under-recoveries to be collected from ratepayers in the RDAFs.

With respect to the ATRs proposed in this filing, we note that they are calculated from the revenue requirements proposed by the Company to be collected from each rate class (Exhs. NG-RRP-2, at 1 (Rev. 1); NG-PP-23, at 180-182 (proposed M.D.P.U. No. 1278)). As noted below in Schedule 1, the Department has approved a different revenue requirement than that proposed by the Company. As such, the Company is directed, in its compliance filing, to file new ATRs by rate class based on the revenue requirement for each rate class approved in this Order.

Further, in D.P.U. 14-136-A, the Department directed the Company to adjust its ATRs to account for the sale of street lighting assets. D.P.U. 14-136-A at 11. The Company added a definition to its revenue decoupling provision for "Streetlight Sales Adjustment" (see n.17 above) in compliance with that Order (Exh. DPU-18-21, Att. at 8). The Department directs the

Company in its compliance filing to include these tariff modifications, as approved in D.P.U. 14-136-A, in its revenue decoupling provision tariff.

Finally, the Department reiterates that the RDM allows companies to modify, on an annual basis, base distribution rates as a result of changes in sales in order to promote the efficient deployment of demand resources. D.P.U. 09-39, at 9, 62-63. Revenue decoupling was intended to provide distribution companies with better financial incentives to pursue a cleaner, more efficient energy future. D.P.U. 07-50-A at 1. Moreover, the Department noted that the conclusions reached in D.P.U. 07-50-A represented general statements of policy. D.P.U. 14-150, at 16-17; Investigation into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-B, at 28-29 (2008).

The Department acknowledges that we have our own concerns about the appropriateness of including street lighting rate classes in a revenue decoupling provision. Currently, the Company does not offer energy efficiency programs directed towards street lighting, and street lighting use is not metered and, as such, distribution revenues are fixed (Tr. 6, at 805-806; Tr. 8, at 1201-1202). Additionally, revenue decoupling was not intended to compensate a company for the sale of street lighting assets. D.P.U. 14-136-A, at 10; see D.P.U. 07-50-A. In the Department's decoupling investigation, we did not contemplate this potential issue, and the model we adopted to decouple rates for all future ratemaking proceedings was silent on street lighting rate classes in RDM. D.P.U. 07-50-B at 26.

For these reasons, the Department expects to address the issue of street lighting rate classes included in the revenue decoupling provisions in a future proceeding. In this regard, the Department puts the Company, and all electric distribution companies, on notice that it has concerns with the inclusion of street lighting rate classes in RDMs, and that we will consider removing street lighting rate classes from RDMs in each electric distribution company's next base distribution rate proceeding. Thus, as part of the initial filing in its next base distribution rate proceeding, each electric distribution company must address and provide justification for the continued inclusion of street lighting rate classes in each company's respective revenue decoupling provision.

V. CAPITAL INVESTMENT RECOVERY MECHANISM

A. Introduction

In the Company's last base rate case, the Department approved National Grid's revenue decoupling provision, which included a CapEx mechanism allowing the Company to recover an annual revenue requirement on incremental capital investments up to a $170 million cap (hereinafter referred to as the "investment cap"). D.P.U. 09-39, at 82.[19] In addition to the $170 million cap, the approved revenue decoupling provision includes a rate cap limiting the annual revenue decoupling adjustment (including the CapEx revenue requirement adjustment to the Annual Target Revenue ("ATR")) to three percent of total revenue (hereinafter referred to as the "rate cap"). D.P.U. 09-39, at 82, 87-88.

Incremental capital investment for each year since the CapEx mechanism commenced is defined as annual capital investment, less the Company's depreciation expense allowed in its last base rate proceeding (Exh. NG-RRP-1, at 54). National Grid calculates each investment vintage year's revenue requirement using an average rate base methodology, incorporating accumulated depreciation and accumulated deferred income taxes associated with that vintage year's

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19 A review of the Company's capital investments made between the date of the decision in D.P.U. 09-39 and the end of the test year in this case is discussed in Section VII.B below.

investments (Exh. NG-RRP-1, at 54). The CapEx mechanism does not allow for the recovery of the revenue requirement for the year of investment for each vintage year, and the Company recovers the revenue requirement for the second year of each vintage beginning March 1st of the subsequent year (Exh. NG-RRP-1, at 54).[20]

B. Company Proposal

National Grid proposes to continue its existing CapEx mechanism with several modifications, including changing its name to the capital investment recovery mechanism ("CIRM") (Exhs. NG-MLR-1, at 16; NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22). The Company proposes to: (1) separate the CIRM from the traditional RDM reconciliation, and operate the mechanisms under separate tariffs; (2) increase the annual investment cap on capital expenditures from $170 million to $285 million; (3) include property taxes in the computation of the CIRM revenue requirement; and (4) apply a one-percent rate cap to the change in annual revenue requirement in the CIRM (Exhs. NG-RRP-1, at 61-62; NG-PP-23, at 178 (proposed M.D.P.U. No. 1277); DPU-32-22).

As set forth in great detail below, the Attorney General opposes all of the proposed modifications. Instead, the Attorney General recommends that the Department should eliminate the CIRM entirely, or, in the alternative, do the following: (1) maintain the investment cap at $170 million, or in the alternative, set the cap at $183 million; (2) limit the scope of capital investments eligible for recovery; (3) include metrics, goals, and/or reporting to provide accountability of customer benefits associated with the Company's capital investments, and to

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20 The Company's current CapEx mechanism, and proposed capital investment recovery mechanism, imposes a 14-month lag on the recovery of the second year revenue requirement for each vintage investment year (Exh. DPU-6-17).

verify that costs are reasonable; (4) include an O&M offset, representing the savings associated with the capital investments; and (5) adjust the rate of return in the CIRM downward to reflect risk reduction associated with the Company's recovery of capital investment with little to no regulatory lag (Exh. AG-DO-CF-1, at 8, 11-12, 18-20; Attorney General Brief at 88-94; Attorney General Brief at 49-53).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General initially recommends discontinuance of the CIRM (Attorney General Brief at 85). The Attorney General maintains that her recommended modifications are necessary to control costs and limit spending to projects that are necessary to provide safe and reliable service (Attorney General Reply Brief at 52, citing Exh. NG-JHP-1, at 29). The Attorney General's specific arguments in support of these positions are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Attorney General recommends elimination of the CIRM entirely (Attorney General Brief at 85). According to the Attorney General, the Department allows alternative regulatory mechanisms only in cases of "extraordinary circumstances," where a company has demonstrated its need to recover incremental costs associated with specific programs between base distribution rate cases (Attorney General Brief at 85, citing Boston Gas Company/Colonial Gas Company/Essex Gas Company, D.P.U. 10-55, at 121-122, 132-133 (2010); D.P.U. 09-39, at 79-80, 82; Bay State Gas Company, D.P.U. 09-30, at 133-134 (2009)). The Attorney General rejects any notion that the Company's investment needs are extraordinary, and she claims that many of these investments will be eligible for recovery through a separate recovery mechanism pending in the Grid Modernization Investigation, D.P.U. 15-120 (Attorney General Brief at 86, citing Company Brief at 97; Attorney General Reply Brief at 48, citing Exh. AG-DO-CF-1, at 12). Therefore, the Attorney General asserts that the Company failed to produce evidence of "extraordinary circumstances" to justify the continuation of the CIRM (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Moreover, the Attorney General argues that the Company is not in a unique position, nor is it under significant pressure to maintain a high degree of system reliability and resiliency, as it claims, because all utilities must invest in their systems for reliability (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 101; Attorney General Reply Brief at 47). Thus, the Attorney General argues that the Company's investment obligations are not extraordinary, but "standard operating procedure" (Attorney General Brief at 86; Attorney General Reply Brief at 47).

Further, the Attorney General dismisses the Company's claim that the CIRM is necessary due to revenue decoupling (Attorney General Brief at 86, citing Exh. NG-RRP-1, at 96-98). According to the Attorney General, the Department has previously rejected other companies' requests for a CIRM when those companies were unable to provide "compelling evidence of lost growth in sales" (Attorney General Brief at 86, citing Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 36 (2014); D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; D.P.U. 07-50-A at 50). In this regard, the Attorney General contends that revenue decoupling ensures the Company will be compensated for lost sales revenue associated with energy efficiency programs and distributed generation ("DG"), which the Company admits is causing its sales forecast to show declining growth (Attorney General Brief at 86-87, citing Exh. DPU-6-14, at 2; Attorney General Reply Brief at 48).[21] Therefore, the Attorney General asserts that because revenue decoupling will not remove the Company's ability to retain additional revenue between its base rate proceedings, there is no need for an additional recovery mechanism. (Attorney General Brief at 87, citing D.P.U. 10-70, at 47).

Additionally, the Attorney General alleges that the Company is financially healthy and highly liquid, and therefore, there is no need for the CIRM (Attorney General Reply Brief at 48). According to the Attorney General, the Company was allowed $40 million in base distribution rates for income taxes in its last base rate proceeding, but because of tax benefits the Company has not and will not pay income taxes for many years (Attorney General Reply Brief at 48, n.18, citing D.P.U. 09-39, at 457; Exh. NG-RRP-2, at 2, 30). Moreover, the Attorney General contends that the Company had sufficient cash available to lend hundreds of millions of dollars to its affiliates through the National Grid USA money pool over the last two years (Attorney General Reply Brief at 48, n.2 citing Exh. AG-1 (National Grid USA Money Pool Report)).

The Attorney General also argues that the Department should consider National Grid's proposed CIRM in conjunction with the Company's other reconciling mechanisms (Attorney General Reply Brief at 48). According to the Attorney General, the Company charges ratepayers on an annual basis for the following: (1) pensions and post-retirement benefits other than pensions ("PBOP") costs; (2) storm costs; (3) energy efficiency program costs; and (4) wind energy contract remuneration (Attorney General Reply Brief at 49, citing Exh. NG-RRP-2, at 2-3). The Attorney General argues that approving the CIRM and allowing these other

21 The Attorney General also notes that the Company receives compensation and incentives related to energy efficiency programs (Attorney General Reply Brief at 48).

reconciling mechanisms exposes ratepayers to an excessive share of risk (Attorney General Reply Brief at 49).

Finally, the Attorney General claims that the CIRM requires an annual prudency review and cost reconciliation, thereby adding to the Department's administrative burden (Attorney General Brief at 87). The Attorney General maintains that based on the Company's prior CIRM experience,[22] future prudency reviews will likely evolve into exhaustive investigations (Attorney General Brief at 87-88, citing docket D.P.U. 10-79; Exh. AG-DO-CF-1, at 35-56). For all these reasons, the Attorney General asserts that the Company's CIRM proposal is not in the best interest of ratepayers and should be discontinued (Attorney General Brief at 87-88; Attorney General Reply Brief at 48). As noted above, in the alternative, the Attorney General asserts that the Department should retain the current investment cap and make specific modifications to the Company's proposal, each of which are discussed below.

c. Investment Cap

The Attorney General argues that the CIRM "significantly reduces and potentially eliminates the important incentive that regulatory lag provides" to control costs because the Company is allowed to recover a return on and of its capital expenditures in the year that they are incurred (Attorney General Brief at 92, citing D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 50, citing D.P.U. 09-39, at 80-81). According to the Attorney General, the Department has found that in the absence of regulatory lag, a cap on the annual CIRM cost recovery would protect ratepayers from over-investment in capital infrastructure and still provide the Company

22 The Attorney General claims that in National Grid's first CapEx investigation, the Company failed to provide project documentation in a timely manner and its filing ultimately lacked clear, cohesive, reviewable project documentation (Attorney General Brief at 88, citing Exh. AG-DO-CF-1, at 35-56).

with sufficient funds to ensure safe and reliable electric service (Attorney General Brief at 92, citing D.P.U. 09-39, at 81-82; Attorney General Reply Brief at 50). In this regard, the Attorney General contends that the Company budgeted for capital spending to align with the $170 million investment cap allowed by the Department when initially approving the CIRM (Attorney General Brief at 92, citing Exhs. DPU-6-7; DPU-18-5).[23] Thus, the Attorney General contends that the $170 million investment cap is an effective means of cost control, and National Grid may include plant additions above the investment cap in the rate base proposal in the Company's next base rate proceeding (Attorney General Brief at 92-93, citing D.P.U. 09-39, at 82-83). Further, she argues that increasing the investment cap will likely lead to a corresponding increase in unfettered capital spending, evident from the Company's capital investment forecast (Attorney General Brief at 92-93, citing Exh. AG-DO-CF-1, at 20; Attorney General Brief at 87, citing Exh. NG-JHP-1, at 29). For these reasons, the Attorney General recommends setting the investment cap at $170 million so as to balance the risk associated with the CIRM between shareholders and ratepayers (Attorney General Brief at 92, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80-81; Attorney General Reply Brief at 48, 49, 50, citing Exh. AG-DO-CF-1, at 20; D.P.U. 09-39, at 80–81.).

In the alternative, if the Department decides to increase the investment cap from $170 million, the Attorney General argues that the Department should set the cap based on a representative level of historic spending, and not on forecasted spending (Attorney General Brief at 93; Attorney General Reply Brief at 50, citing D.P.U. 1580, at 13–17, 19; D.P.U. 136, at 3;

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23 However, she also alleges that the $170 million investment cap has not prevented the Company from exceeding it (Attorney General Reply Brief at 50, citing RR-DPU-13, Att.).

D.P.U. 19992, at 2; D.P.U. 18204, at 4; D.P.U. 18210, at 2–3; D.P.U. 18264, at 2-4; Attorney General Reply Brief at 51).[24] According to the Attorney General, when the Department grants a capital recovery mechanism, it bases it on an average of historical expenditures, not on company projections. (Attorney General Reply Brief at 51, citing D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82). Therefore, the Attorney General asserts that the investment cap should be based on a five-year average of plant additions (excluding cost of removal), instead of a three-year average[25] that the Department used to establish the $170 million investment cap (Attorney General Brief at 93, citing D.P.U. 09-39, at 82; D.P.U. 15-80/D.P.U. 15-81, at 53). The Attorney General maintains that a five-year average of plant additions (excluding cost of removal) is more appropriate than a three-year average because the Company's plant additions in 2013 and 2015 were not representative of a typical year (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).[26] Further, the Attorney General maintains that a five-year average for plant additions of $183 million provides an appropriate balance of sufficient funding for the Company and ensuring safe and reliable service (Attorney General Brief at 93, citing RR-DPU-14; Attorney General Reply Brief at 49, 51).

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24 The Attorney General alleges that the Company's proposed $285 million cap is based on future projections (Attorney General Reply Brief at 50-51).

25 The Attorney General calculates the Company's three-year average of plant additions (excluding cost of removal) at $197 million (Attorney General Brief at 93, citing RR-DPU-9).

26 The Attorney General explains that the Company's spending in 2015 was significantly higher than the prior years (i.e., $259 million in 2015; $180 million in 2014; $151 million in 2013; and $139 million in 2012), and in 2013, storm restoration efforts and issues related to the SAP implementation affected the Company's plant additions (Attorney General Brief at 93, citing RR-DPU-9; RR-DPU-14).

d. Modifications to the CapEx/CIRM

i. Scope

The Attorney General recommends that the Department direct the Company to narrow the scope of its CIRM to a certain category of spending (Attorney General Brief at 88; 89-90; Attorney General Reply Brief at 48, 49-50, 51). According to the Attorney General, a capital cost recovery mechanism is most effective when it is targeted to provide specific improvements and goals, and allows interested parties to track the costs associated with specific investment activities (Attorney General Brief at 88, citing D.P.U. 10-70, at 47-50; D.P.U. 10-55, at 66). The Attorney General explains that capital cost recovery mechanisms used by other states are more narrow and targeted compared to the Company's CIRM, and these mechanisms recover specific capital costs such as solar, renewable energy, or smart grid investments (Attorney General Brief at 88-89, citing Exh. AG-DO-CF-1, at 10-11; Tr. 15, at 1601-1603, 1683; Attorney General Reply Brief at 48-49, citing Tr. 15, at 1683). Additionally, the Attorney General explains that Connecticut Light and Power's ("CL&P") capital cost recovery mechanism authorizes recovery of specific projects that improve storm hardening infrastructure, and in 2013, represented an annual revenue requirement of $34.9 million (Attorney General Brief at 89, citing RR-NG-2, at 1; Attorney General Reply Brief at 52). The Attorney General does not make a specific recommendation regarding a spending category to limit the scope of the Company's CIRM, but she acknowledges that the Company already recovers costs for solar investments, smart grid technologies, and storm-related costs separately from the CIRM and base rates (Attorney General Brief at 89, citing Exhs. NG-RRP-1, at 107-110; AG-DO-CF-1, at 12; Tr. 15, at 1683).

ii. Benefits

The Attorney General recommends that the CIRM include a mechanism to account for customer benefits achieved in conjunction with annual capital spending (Attorney General Brief at 90, citing Exh. AG-DO-CF-1, at 13). The Attorney General claims that there is no evidence that National Grid's proposed CIRM will contribute to cost-effective, safe, and reliable service (Attorney General Brief at 90). For example, the Attorney General explains that the budget for "Asset Condition," which covers the replacement of assets the Company believes will fail, is forecasted to increase 116 percent over historical spending (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19-20). The Attorney General expects that this increase in spending would lead to a decrease or leveling out in the budget for "Damage/Failure," which covers the costs for the replacement of failed assets (Attorney General Brief at 90, citing Exh. NG-JHP-1, at 19). The Attorney General claims, however, that the Company's "Damage/Failure" budget category forecast for 2017-2019 increases 32 percent over historical spending (Attorney General Brief at 91, citing Exh. AG-7-5, Att.). From this data, the Attorney General contends that the Company is planning to replace assets with a low probability of failure to increase the costs recovered through the CIRM, thereby providing the Company with an opportunity for "gold-plating" (Attorney General Brief at 90-91, citing Exh. AG-7-5, Att.).

Further, the Attorney General maintains that other utilities include reports on the effectiveness of their capital cost recovery mechanisms (e.g., TIRF programs[27] include reports on leaks and CL&P provides data on system resiliency) (Attorney General Brief at 91,

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27 TIRF refers to targeted infrastructure recovery factor programs that are designed to allow for annual recovery by gas distribution companies of the revenue requirement associated with incremental investment for the replacement of leak-prone infrastructure. See, e.g., D.P.U. 09-30, at 121.

citing Exh. AG-DO-CF-1, at 13, 16; RR-NG-2, Att. 2, at 11-12). The Attorney General asserts that there should be greater accountability in the Company's CIRM mechanism because it is much broader than a TIRF or CL&P's capital cost recovery mechanism (Attorney General Brief at 91). Therefore, the Attorney General recommends that the Department require the Company to re-engage with stakeholders to establish metrics, goals, and reporting requirements to ensure that the investments made in the CIRM deliver benefits to customers at a reasonable cost (Attorney General Brief at 91, citing Exh. AG-DO-CF-1, at 16-17; Attorney General Reply Brief at 52, n.20).

iii. O&M Offset

The Attorney General alleges that through the CIRM, National Grid will complete system replacements and enhancements, and as a result, the number and cost of failures will decline (Attorney General Brief at 91, citing Tr. 2, at 251-252; Attorney General Reply Brief at 52). For example, the Attorney General explains that the installation of reclosers on circuits would limit the area crews that the Company would need to patrol to locate outages (Attorney General Brief at 91, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). The Attorney General maintains that with a decline in outages, the Company also should experience lower O&M expenses (Attorney General Brief at 92, citing Exh. AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 52, citing Exh. AG-DO-CF-Rebuttal-1, at 8). Therefore, the Attorney General recommends that the Company's CIRM include an O&M offset associated with the O&M savings resulting from additional capital investments (Attorney General Brief at 91-92, citing Exhs. AG-DO-CF-1, at 18; AG-DO-CF-Rebuttal-1, at 8; Attorney General Reply Brief at 50, 52, 53).

iv. Rate of Return

The Attorney General argues that if the Department decides to allow the CIRM as proposed by the Company, the Department should adjust downward the rate of return that the Company is allowed in the CIRM (Attorney General Brief at 94; Attorney General Reply Brief at 49, citing D.P.U. 07-50-A, at 71; Bay State Gas Company, D.T.E. 05-27, at 302 (2005); D.T.E. 02-24/02-25, at 229; D.T.E. 03-40, at 363; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977)). The Attorney General argues that a lower rate of return is reflective of the Company's reduction in risk associated with the recovery of most, if not all, of its capital investments in between base rate proceedings, with little regulatory lag (Attorney General Brief at 94, citing Exh. AG-DO-CF-1, at 20).

2. PowerOptions

PowerOptions argues that the Department must take a close look at proposed tracking mechanisms, such as the proposed CIRM, and decide whether they are warranted and in the best interest of ratepayers (PowerOptions Reply Brief at 9, citing D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52.) According to PowerOptions, while the tracking mechanisms benefit utility companies in terms of timely cost recovery, they are administratively onerous with annual filings requiring review by all interested parties, require numerous reconciliations and true-ups, and often result in additional charges to customers beyond base rates (PowerOptions Reply Brief at 9-10). Further, PowerOptions notes that the Department has found that where a company failed to demonstrate there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers (PowerOptions Reply Brief at 10, citing D.P.U. 15-80/D.P.U. 15-81 at 54; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50-52).

Based on these considerations, PowerOptions argues that the Department must take a close look at whether extraordinary circumstances prevent National Grid from acquiring the capital necessary to make required investments in its infrastructure (PowerOptions Reply Brief at 10). PowerOptions contends that if the Department allows the CIRM, then it must decide whether an investment cap increase to $285 million is warranted and, if so, the Department needs to determine the process to ensure that there is appropriate oversight over these investments and proper review of the Company's three-year capital investment plan (PowerOptions Reply Brief at 10-11).

3. Company

a. Introduction

National Grid submits that its capital investments are increasing: (1) to maintain a resilient, modern electric grid substantially improved through technology; and (2) to meet customers' expectations for reliable service and information (Company Brief at 165). According to the Company, two modifications will improve the CIRM's operation (Company Brief at 166). First, National Grid proposes to increase the current investment cap of $170 million to $285 million, representative of the Company's actual plant additions during the test year (Company Brief at 166). Second, the Company proposes to include property tax expense in the computation of the revenue requirement because it is the "normal course for capital investment recovery mechanisms approved by the Department in other contexts" (Company Brief at 166).

The Company disagrees with the Attorney General's recommendation to eliminate the CIRM, and it rejects the Attorney General's alternative recommended modifications. The Company's positions regarding these issues are discussed in further detail below.

b. Elimination of the CapEx/CIRM

The Company argues that discontinuing the CIRM is implausible, especially considering the Commonwealth's energy efficiency programs, DG resources, and demand response programs that have been put in place since 2008 (Company Brief at 168). According to National Grid, the Department has recognized the direct impact on the Company's business when average consumption declines as a result of these conservation initiatives, namely the Company's inability to retain incremental sales revenue to support capital investment on a year-to-year basis (Company Brief at 168-169). National Grid acknowledges that revenue decoupling reimburses the Company for lost sales revenue due to reductions in consumption since setting its ATR (Company Brief at 165-166). However, the Company maintains that revenue decoupling also negates growth in sales that would have supported increases in the Company's cost of service between base rate proceedings (Company Brief at 165-166).[28] Thus, National Grid disagrees with the Attorney General's assertion that, through decoupling, the Company already is reimbursed and made whole for sales losses due to energy efficiency (Company Reply Brief at 69, citing Attorney General Reply Brief at 48).

Instead, National Grid contends that revenue decoupling does not return the value of sales volumes to the Company that is over and above the test year and were historically available to fund capital expenditures between base rate proceedings (Company Reply Brief at 70).

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28 National Grid attributes increases in the cost of service largely to capital investment since its last base rate proceeding (Company Brief at 165-166).

According to National Grid, the Attorney General has failed to discredit evidence provided by the Company that the CIRM is necessary as a result of the Department's efforts to promote energy efficiency, demand resources, renewable energy, and DG (Company Reply Brief at 69, citing Exh. DPU-6-14). Thus, National Grid argues that if its revenues are decoupled from sales, the Company must retain its CIRM with the proposed modifications (Company Brief at 169-170).

Further, National Grid claims that its declining sales forecast demonstrates the success of the Department's efforts to achieve the objectives in D.P.U. 07-50-A (Company Brief at 170). According to the Company, without the downward sales pressure from DG and energy efficiency, the Company would have realized sales growth to offset its plant additions (Company Brief at 170, 171, citing Exh. DPU-6-14, Att.; Company Reply Brief at 69). According to the Company, the Attorney General did not rebut, evaluate, critique, or challenge: (1) the Company's sales forecast; or (2) that the Company's energy efficiency savings as a percent of total kilowatt hour ("kWh") delivery have doubled since 2010 (Company Reply Brief at 69; Company Brief at 168, citing Exh. NG-MLR-1, at 13).

Moreover, National Grid disputes the Attorney General's argument that the Company receives compensation and incentives for its energy efficiency programs (Company Reply Brief at 70). National Grid maintains that energy efficiency program costs are passed through to customers and any incentives that the Company receives are not sufficient to fund the Company's plant additions (Company Reply Brief at 70). For all these reasons, the Company asserts that the Attorney General did not provide creditable evidence in support of her position to discontinue the Company's CIRM (Company Reply Brief at 70).

c. Investment Cap

In response to the Attorney General, the Company argues that the current $170 million investment cap is insufficient for recovery of annual capital expenditures (Company Brief at 173). According to the Company, it has exceeded the $170 million cap by a total of $178 million since the CIRM's implementation (Company Brief at 173). Additionally, the Company argues that its plant additions and cost of removal in the test year alone exceeded the $170 million cap by more than $100 million (Company Brief at 173). Therefore, the Company asserts that the Attorney General's recommendation to set the investment cap at either $170 million or $183 million is not supported by record evidence (Company Reply Brief at 73).

In support of the proposed $285 million investment cap, the Company argues that it is under pressure to meet expanding service requirements and increased investment in distribution infrastructure (Company Brief at 166, citing Exh. NG-RRP-1, at 60). The Company maintains that it cannot meet the growing demand for capital investment without the CIRM, and that it will need to spend up to the $285 million investment cap to continue to meet its capital investment goals over the next three years (Company Brief at 167, citing Exh. NG-RRP-1, at 60; Company Reply Brief at 72, citing Exh. NG-JHP-1, at 29). The Company notes that it invested approximately $1.3 billion in its system between the end of 2008 and June 30, 2015 (Company Brief at 166, citing Exh. NG-RRP-1, at 60). Further, National Grid points out that it incurred $260 million in plant in service and $25 million in cost of removal in the test year (Company Brief at 166-167, citing Exh. DPU-32-22). Therefore, the Company asserts that a $285 million investment cap, based on actual capital expenditures in the test year, is more representative of the

Company's actual and projected investments (Company Brief at 174, citing Exh. NG-JHP-1, at 29).

National Grid also argues that increasing the investment cap to $285 million is in the best interest of ratepayers because it will contribute to maintaining service at current levels and assist the Company in complying with the Department's service-reliability metrics (Company Brief at 176, citing Exh. AG-7-5; Company Reply Brief at 73). National Grid claims that an investment cap based on a historical three-year or five-year average will not achieve the intended capital investment cost recovery and will render the CIRM moot (Company Brief at 174). In the alternative, the Company suggests that the Department approve a rolling three-year average investment cap, up to $285 million (Company Brief at 174, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277; Company Reply Brief at 73, citing Exh. NG-JHP-Rebuttal-1, at 4-5; Tr. 2, at 256-277).

d. Property Taxes

National Grid notes that the Attorney General did not challenge the Company's proposal to include property taxes in the CIRM (Company Reply Brief at 73). In support of the property tax modification, the Company explains that the current CIRM does not allow for recovery of property tax associated with annual capital additions made after the test year, which National Grid claims contradicts the Department's standard practice (Company Brief at 167, citing Exh. NG-RRP-1, at 62). The Company maintains that every other capital recovery mechanism approved by the Department includes property tax recovery, except for the recent mechanism approved for Fitchburg Gas and Electric Light Company (Company Brief at 162, 167, citing D.P.U. 15-80/D.P.U. 15-81, at 54; Tr. 1, at 95-96; Boston Edison

Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-82-A, at 53, 61 (2010)). The Company purports that incremental capital investment causes incremental increases in property tax (Company Brief at 167, citing Exh. DPU-10-2). Thus, National Grid argues that property taxes are directly attributable to the Company's capital additions and an unavoidable element of the CIRM revenue requirement (Company Brief at 167, citing Exh. NG-RRP-1, at 62). Additionally, the Company adds that the Department did not perform an investigation that would provide a foundation to exclude property tax from the CIRM (Company Brief at 167).

Moreover, National Grid claims that it did not originally propose to include property taxes in its CapEx proposal in D.P.U. 09-39 because the mechanism was one of four proposed rate recovery mechanisms: (1) the approved RDM; (2) the approved CapEx mechanism; (3) a proposed CapEx mechanism to recover projected capital investments; and (4) a proposed adjustment mechanism for net inflation (Company Brief at 161-162, citing D.P.U. 09-39, at 10). National Grid claims that it did not propose to recover property taxes in the approved CapEx mechanism because its proposed net inflation adjustment mechanism would have adjusted its total operating expense, including property taxes (Company Brief at 162, citing D.P.U. 09-39, Exh. NG-HSG-RR-8, at 2). The Company asserts that the Department did not "correct for this purposeful exclusion when it approved capital-cost recovery, while denying the net inflation adjustment" (Company Brief at 162). National Grid describes this result as an "inadvertent exclusion" and a "mistake" by the Department in D.P.U. 09-39 (Company Brief at 162). Therefore, National Grid concludes that there is no basis to exclude property taxes in the calculation of the CIRM revenue requirement in the instant proceeding (Company Brief at 167; Company Reply Brief at 73).

e. Response to Attorney General's Recommended Modifications

The Attorney General recommends several modifications to the CIRM that National Grid claims lack justification, are unsubstantiated, and are contrary to the purposes of the CIRM (Company Brief at 176; Company Brief at 171-172, citing Attorney General Brief at 88; Company Reply Brief at 70). The Company argues that the Attorney General failed to provide persuasive testimonial evidence to support her recommended modifications to the proposed CIRM (Company Reply Brief at 71-72, citing Tr. 15, at 1602-1605, 1607-1608, 1613, 1617-1618, 1622-1628, 1630-1632). Further, National Grid contends that the Attorney General did not provide analytical support for any of her proposed modifications (Company Reply Brief at 71).

i. Scope

National Grid claims that the Attorney General's recommendation to narrow the scope of cost recovery in the Company's proposed CIRM, based on the design of capital cost recovery mechanisms in other jurisdictions, is unsubstantiated (Company Brief at 172, citing Attorney General Brief at 89; Tr. 15, at 1600-1609). In particular, the Company argues that the Attorney General's evidence of CL&P's storm hardening cost recovery mechanism is actually tied to a capital budget recovered though CL&P's base rates on a future test year basis (Company Brief at 172, citing RR-NG-2, Att. at 1, 8). Therefore, National Grid asserts that capital cost recovery is more favorable to electric distribution utilities in Connecticut than Massachusetts, a fact that the Company claims the Attorney General failed to recognize (Company Brief at 172-173).

ii. Benefits

The Company rejects the Attorney General's recommendation that the Department should include metrics to improve the accountability of customer benefits from the Company's capital spending in the CIRM (Company Brief at 176). The Company maintains that the Attorney General did not explain how the Department's existing service-quality metrics are deficient or suggest an alternative mechanism to include in the CIRM (Company Brief at 176).

iii. O&M Offset

National Grid contends that the Attorney General did not support her position to include an O&M offset in the CIRM (Company Brief at 176; Company Reply Brief at 73). The Company maintains that the O&M offset in the gas system enhancement plan cost recovery mechanism represents the elimination of a discrete O&M expense caused by gas leaks that no longer need repairs because the leaky pipe was replaced (Attorney General Brief at 176). According to the Company, there are no similarities in O&M savings between the CIRM and the gas system enhancement plan (Company Brief at 176; Company Reply Brief at 73).

iv. Rate of Return

Finally, the Company claims that the Attorney General did not rebut the Company's evidence showing that a deduction to the cost of capital is not warranted or appropriate (Company Brief at 176). Therefore, National Grid asserts that the Attorney General's modification to the rate of return on invested capital should be denied (Company Brief at 173, 176).

D. Analysis and Findings

1. Introduction

In D.P.U. 07-50-A at 48, the Department recognized that full revenue decoupling for electric companies would, all other things being equal, remove the opportunity for companies to retain additional revenues from sales growth between base rate proceedings -- revenues that companies could have used to pay for increased O&M costs, costs related to system reliability, and capital expansion projects. See D.P.U. 11-01/D.P.U. 11-02, at 73-74, 107; D.P.U. 10-70, at 47. The Department also recognized that changes in a distribution company's costs could arise from inflationary pressures on the prices of the goods and services it uses. D.P.U. 07-50-A at 49; see also D.P.U. 10-70, at 53. Accordingly, the Department stated that, along with revenue decoupling, it would consider company-specific proposals that adjust target revenues to account for capital spending and inflation but that a company would bear the burden of demonstrating the reasonableness of its proposal. D.P.U. 07-50-A at 50; see also D.P.U. 11-01/D.P.U. 11-02, at 107-108; D.P.U. 10-70, at 47.

In prior cases, when deciding whether to adopt a new capital cost recovery mechanism, the Department closely examined whether the mechanism was warranted and whether it was in the best interest of ratepayers. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52; D.P.U. 09-39, at 80-84.[29] The Department has allowed capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover

29 National Grid was the first electric distribution company to receive approval for a CapEx mechanism following revenue decoupling. D.P.U. 09-39, at 80-84. Subsequently, the Department approved a CapEx mechanism for Fitchburg Gas and Electric Light Company. D.P.U. 15-80/D.P.U. 15-81, at 50. The Department also previously rejected a CapEx mechanism for Western Massachusetts Electric Company. D.P.U. 10-70, at 52.

incremental costs associated with capital expenditure programs between base rate proceedings. D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve a capital cost recovery mechanism as an element of decoupling. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; see also D.P.U. 07-50-A at 50. The Department has found that, where a company failed to demonstrate that there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers. D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50, 52.

2. Continuation of the CapEx/CIRM

National Grid acknowledges that the CapEx mechanism approved by the Department in D.P.U. 09-39 has not provided the Company with the level of benefits expected when originally proposed (Exh. NG-RRP-1, at 60-62). Thus, the Company proposes to increase the investment cap in its CIRM from $170 million to $285 million and apply a one-percent rate cap to the change in annual revenue requirement (Exhs. NG-RRP-1, at 61-62; DPU-32-22). Additionally, National Grid argues that the current CapEx mechanism does not provide for recovery of property taxes, a direct component of capital investment (Exhs. NG-RRP-1, at 62; DPU-10-2). Accordingly, the Company has proposed a modified CIRM that includes an investment cap of $285 million and for recovery of property taxes based on the ratio of test year property taxes to rate base (Exh. NG-RRP-1, at 61-62).

The Company must meet its service requirements and investment in distribution infrastructure, which has steadily increased since its last rate case (Exhs. NG-RRP-1, at 60; NG-MLR-1, at 6; DPU-18-5). See Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57 (2009) (a monopoly service provider has a public service obligation to provide reliable service at the lowest cost to customers); Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 6-7 (1986); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). National Grid invested approximately $1.3 billion in its electric distribution system from 2009 through June 30, 2015, and its actual expenditures on capital investment have exceeded the $170 million annual investment cap by an aggregate $178 million over the same period (Exhs. NG-RRP-1, at 60-61; AG-7-5, Att.; AG-16-2, Att.). The Company expects that its workload will increase significantly to provide safe and reliable service and it forecasts capital expenditures to increase from $302 million in 2015 to $311 million in 2017 (Exhs. DPU-10-6; DPU-18-5; AG-7-5). Moreover, the Company's test year plant additions were more than twice the level of the Company's depreciation expense of $127 million (Exhs. NG-RRP-1, at 60; NG-RRP-2, at 5 (Rev. 3)). Accordingly, National Grid would be unable to fully fund its test year level of capital expenditures, much less fully fund its projected increases in capital expenditures, through its base rate depreciation expense.[30]

National Grid also is experiencing an unprecedented level of DG and energy efficiency installations on its system, which cause diminishing sales revenues and increasing workload and expenses to administer the interconnection process for these installations (Exhs. NG-MLR-1,

[30] Depreciation expense is a non-cash expense associated with the use of an asset. Utilities often use depreciation expense as a funding source for capital expenditures.

at 13, 19; DPU-6-21). The Company ranks fifth in the United States in solar interconnections, at 405.3 megawatts ("MW") of interconnected DG solar over the period 2009-2015 (Exh. NG-MLR-1, at 19-20). Without the effect of increasing DG and energy efficiency, the Company's sales forecast derived solely on the basis of economic data would show positive sales growth over a five-year planning period (Exh. DPU-6-14, at 3). Thus, the Company estimates that DG and energy efficiency are reducing sales by approximately 2.3 percent cumulatively per year based on historical installations, and could increase to sales reductions of 6.5 percent cumulatively per year over a five-year planning period, based on additional installations (Exhs. DPU-6-14, at 4; DPU-6-14, Att. at 21).

Based on these considerations, the Department finds that the Company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate cases. Accordingly, we will allow the operation of the Company's CIRM. D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134. In this regard, we further find that the CIRM shall operate independent of the Company's revenue decoupling provision. Although the Department stated that we would consider proposals to adjust ATR in an RDM, separating the mechanisms produces the same result for the Company. The RDM reconciliation will annually true-up the over- or under-recovery of base distribution rates, while the CIRM will annually true-up the over- or under-recovery of the Company's allowed annual capital expenditure. See D.P.U. 07-50-A at 50. Separating the CIRM component from the RDM allows for administrative efficiency and the application of separate rate caps.

National Grid proposes an annual rate cap on the CIRM revenue requirement at one percent of total revenues (Exh. NG-PP-23, at 178, (proposed M.D.P.U. No. 1277, at sheet 3)). The Department finds that a one-percent rate cap adequately protects ratepayers from excessive annual increases to distribution rates. See D.P.U. 10-55, at 133. To the extent that the application of the one-percent rate cap results in a CIRM revenue requirement that is less than that calculated, National Grid shall defer the difference and include in the CIRM reconciliation for recovery in the subsequent year. Carrying charges shall be calculated on the average deferred balance using the customer deposit rate (Exh. NG-PP-23, at 178 (proposed M.D.P.U. No. 1277, at sheet 3)). Additionally, the one-percent rate cap is consistent with other capital tracking mechanisms approved for utilities in Massachusetts. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 53-54; D.P.U. 10-55, at 133.

The Department now allows the Company's CIRM to operate separately from the Company's revenue decoupling provision. Below, the Department addresses the Company's proposed modification to increase the investment cap to $285 million and to include property taxes in the annual revenue requirement. We also address the Attorney General's recommended modifications to the CIRM.

3. Investment Cap

The Company proposes to increase its investment cap to $285 million, based on its test year plant additions and cost of removal (Exhs. NG-RRP-1, at 61; DPU-10-6, Att.; RR-DPU-9; RR-DPU-14). The Attorney General asserts that the investment cap should remain at $170 million, or in the alternative, be set at $183 million, representing the five-year average of plant additions, excluding cost of removal (Exh. AG-DO-CF-1, at 8; Attorney General Brief at 93, citing RR-DPU-14).

Capital cost recovery mechanisms reduce and potentially eliminate the important incentive that regulatory lag provides to companies to maintain an appropriate balance between investing in capital improvements and incurring O&M expenses. D.P.U. 09-39, at 81. To reach a balance between: (1) providing the Company with sufficient capital funding to ensure the safety and reliability of the electric service that it provides to its ratepayers; and (2) protecting its ratepayers against the incentive the Company has to overinvest in capital infrastructure in order provide earnings to its shareholders, the Department has directed companies to implement investment caps. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 81-82.

After review of the record and the arguments of the parties, the Department finds it appropriate to implement an investment cap based on the historical three-year average of capital spending, or $249 million (Exh. DPU-10-6 & Att.).[31] We conclude that using this three-year average of capital spending as the limit on CIRM revenue requirement is appropriate because it is representative of National Grid's current capital investment needs and, as such, strikes the appropriate balance between: (1) providing the Company with sufficient funds to ensure safe and reliable electric service; and (2) protecting ratepayers from over-investment in capital infrastructure. D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 82.[32]

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31 The $249 million historical three-year average of capital spending (including cost of removal) is calculated based on capital spending of approximately $176 million in 2013, $270 million in 2014, and $302 million in 2015 (Exh. DPU-10-6 & Att.).

32 The Department expects the Company's first CIRM filing to reflect six months of capital investments (i.e., July 1, 2015-December 31, 2015). Therefore, the Department directs the Company to prorate the annual $249 million investment cap (i.e., $124.5 million) to

The Department makes no determination regarding the optimal level of investment the Company should make in its distribution infrastructure in order to provide safe and reliable electric service to its ratepayers in satisfaction of its public service obligation.[33] The Company's maintenance and replacement activities may lead the Company to identify capital investments that exceed the level of the three-year average

4. Property Taxes

In D.P.U. 15-80/D.P.U. 15-81, the Department excluded property taxes from Fitchburg Gas and Electric Light Company's capital cost recovery mechanism on the basis that capital cost recovery mechanisms are not intended to provide a company with dollar-for-dollar recovery of capital investments between rate cases, and are intended to provide rate relief in between base distribution rate cases to fund capital investments that otherwise were available to be funded through sales growth prior to decoupling. D.P.U. 15-80/D.P.U. 15-81, at 54. Based on the record in this proceeding, however, it is apparent that the exclusion of property taxes does not provide the appropriate rate relief between base rate proceedings to fund capital investments that were available to be funded through sales growth prior to revenue decoupling (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Further, based on the record in this proceeding, the Department is persuaded that property taxes are directly attributable to the Company's capital additions (Exhs. NG-RRP-1, at 62; DPU-10-2; Tr. 1, at 95-96; Tr. 9, at 1533-1535). Incremental increases in property taxes are inextricably linked to incremental

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account for only six months of capital investment in the first annual CIRM filing following this Order.

33 In this regard, the Department relies on the Company to make sound management, business, and engineering decisions.

capital investment funded through the CIRM. Moreover, under the Company's current CapEx mechanism, the Company's return on rate base was 1.18 percent (compared to its authorized return of 8.14 percent) (Exhs. NG-MLR-1, at 4; AG-16-1). See also Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39-A at 38 (2010). The Department concludes property taxes represent a significant cost related to capital investments, and excluding them from the CIRM may contribute to earnings erosion and may negatively affect capital investment.

We recognize that the Department's decision today shifts from the policy direction previously stated in D.P.U. 15-80/D.P.U. 15-81. However, we find that the change here is necessary in order to provide the Company with a necessary and appropriate level of rate relief. Moreover, the Department's goal in the inclusion of property taxes in the CIRM is to mitigate the need for base rate relief prior to the five-year interval prescribed by § 94, ultimately to the benefit of ratepayers. Further, we note that permitting the Company to recover property taxes associated with CIRM investments will not result in dollar-for-dollar recovery of all property taxes. The Company proposes to include property taxes in its CIRM using a ratio of total annual property taxes paid in the test year to total taxable net plant in service in the test year (Exhs. NG-PP-23, at 176 (proposed M.D.P.U. No. 1277, at sheet 1); DPU-18-8, Att.). Based on the Company's original cost of service data, the property tax rate for the CIRM calculation is 2.63 percent (Exhs. NG-RRP-2, at 28, 30 (Rev. 1); DPU-18-8). The Company multiplies the 2.63 percent property tax rate by net plant to determine the property tax expense recoverable through the CIRM (Exh. DPU-18-8). Because National Grid is not permitted to recover the revenue requirement associated with the investment vintage year, the full property tax expense