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August 12, 2025

***VIA ELECTRONIC FILING***

Oregon Public Utility Commission  
Attn: Filing Center  
201 High Street SE, Suite 100  
Salem, OR 97301-3398

**Re: UM 2273—Investigation into House Bill 2021 Implementation Issues**

PacifiCorp d/b/a Pacific Power respectfully submits the following opening comments in response to the Public Utility Commission of Oregon's request for comments on the draft order prepared by the Administrative Hearings Division addressing the cost cap provisions set forth in Section 10 of House Bill 2021.

If you have any questions about this filing, please contact Amira Streeter, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

A handwritten signature in black ink, appearing to read "Robert Meredith".

Robert Meredith  
Director, Regulation

Enclosures

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

**UM 2273**

In the Matter of

PUBLIC UTILITY COMMISSION OF  
OREGON,

Investigation Into House Bill 2021  
Implementation Issues.

PacifiCorp Opening Phase 2 Comments

**I. INTRODUCTION**

PacifiCorp d/b/a Pacific Power respectfully responds to the Public Utility Commission of Oregon’s (OPUC or Commission) request for comments on a draft order prepared by the Administrative Hearings Division (AHD) addressing the cost cap provisions set forth in Section 10 of House Bill (HB) 2021.<sup>1</sup> As discussed below, there are several important issues that the Commission should consider when finalizing its order to implement HB 2021’s cost cap.

PacifiCorp’s comments are organized to address the sections of the Commission’s draft order, the counterfactual portfolio, and the Commission’s provided hypothetical example. Through these comments, PacifiCorp makes the following recommendations to the Commission:

- With regards to the investments and costs eligible for HB 2021 cost cap inclusion, PacifiCorp recommends the Commission consider adding additional clarity to the draft order that provides guidance on the types of co-benefits it might consider and how those co-benefits might be quantified for purposes of allocating costs or investments from actions that contribute to the HB 2021 cost cap. Further, PacifiCorp recommends the Commission add clarity on the information it will need from the utility in a section 10 filing to allocate costs for HB 2021 actions to the cost cap.
- The draft order creates a significant issue with regards to the timing of a section 10 filing. It is simply too late to require a section 10 filing after a utility has committed to a project; at that point the costs are incurred, and seeking relief from the cost cap is moot. Additionally, if cost cap relief is not granted, it could be too late to take additional procurement actions necessary to comply with HB 2021 emissions-reduction targets. PacifiCorp recommends the Commission establish a fast-track cost cap proceeding that

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<sup>1</sup> *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Notice and Memorandum (May 27, 2025).

can be resolved within 90–120 days that would occur while the company seeks approval of the final shortlist during a request for proposals (RFP) process.

- PacifiCorp recommends that the Commission consider a broader view of the interaction between the HB 2021 and RPS cost caps, specifically in a manner that allows for consideration of the co-benefits of a project that could apply to both standards.
- PacifiCorp recommends that the Commission consider adding additional clarity on how forecasted annual revenue requirement will be determined and tracked over time.

## II. COMMENTS ON DRAFT ORDER

### A. Investments and Costs Eligible for HB 2021 Cost Cap Inclusion

PacifiCorp supports language in the draft order finding that when determining a cost or investment contributes to compliance, the Commission must also determine what costs or investments are being displaced and include only the difference in the cost cap calculation.<sup>2</sup> In order to better understand and define the investments and costs that are eligible for inclusion in the HB 2021 cost cap, PacifiCorp requests additional clarity.

Specifically, there is significant uncertainty in how the Commission will determine whether co-benefits from specific investments are eligible for HB 2021’s cost cap. The draft order finds compliance with section 1 through 15 of HB 2021 must be a “significant purpose of the action.”<sup>3</sup> The draft order contemplates consideration of other drivers (or co-benefits) of an action to “consider the appropriate portion of the cost or investment for inclusion in the cost cap.”<sup>4</sup> This language is intended to chart a path between two extremes—one extreme is limiting actions to those where compliance is the sole motivation and another extreme where any action that reduces greenhouse gas emissions would count toward the cost cap.<sup>5</sup> While it is reasonable to find a compromise between two bookend interpretations of costs that should be considered in a cost cap proceeding, this language needs additional specificity on the types of co-benefits that should be considered or how an allocation of costs or investments will be assigned as a contributor to the HB 2021 cost cap.

Generation resources, transmission assets, and distribution assets are all parts of a complex and interconnected network that collectively allows a utility to reliably serve its customers at a reasonable cost. Any single project or action that adds to, or modifies, this complex network provides a wide range of co-benefits. For example, a new renewable resource paired with a storage resource that is connected to the grid produces non-emitting energy that facilitates compliance with HB 2021 emission-reduction targets. That same facility might also improve reliability benefits, which can be measured using a variety of metrics (i.e., capacity

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<sup>2</sup> *Id.* at 7.

<sup>3</sup> *Id.* at 5.

<sup>4</sup> *Id.* at 6.

<sup>5</sup> *Id.* at 5.

contribution value to satisfy resource adequacy needs, operating reserve benefits, resource sufficiency value as needed to participate in expanding organized market activities, frequency response, etc.). Some categories of co-benefits can be readily quantified or reasonably projected (i.e., energy benefits by avoiding market purchases or higher cost resources) and some cannot (i.e., frequency response, contributions toward meeting resource sufficiency tests in an organized market). Consequently, ambiguity in the draft order sets the stage for subjectivity and controversy. To avoid these complications, PacifiCorp recommends the Commission consider adding additional clarity to the order that provides guidance on the types of co-benefits it might consider, and how those co-benefits might be quantified for purposes of allocating costs or investments from actions that contribute to the HB 2021 cost cap. Further, PacifiCorp recommends the Commission add clarity on the information it will need from the utility in a section 10 filing to allocate costs for HB 2021 actions and appropriate co-benefits to the cost cap.

## **B. Forecasted Costs**

PacifiCorp supports the Commission’s draft order concluding that an IRP/CEP would not provide reasonably concrete forecasted costs for HB 2021 cost cap purposes. An IRP/CEP is well suited to provide analysis showing how HB 2021 compliance costs might impact customers and to signal for the Commission and stakeholders whether cost pressures might trigger a future section 10 cost cap proceeding. Similarly, PacifiCorp supports statements in the draft order explaining how denying review of a cost cap evaluation until a utility seeks to recover project costs in rates makes the cost cap meaningless due to regulatory lag.

The draft order expressly says that the Commission “will consider a utility commitment to a project as sufficient to meet the definition of ‘forecast costs’.”<sup>6</sup> It is not clear why a section 10 filing that relies on forecast costs would be needed once the utility is committed to a project. In this context, once the utility commits to a project to meet HB 2021 targets, in whole or in part, it establishes a contractual obligation with a third party (i.e., a developer or a construction contractor) that authorizes the project to move forward at some cost. This brightline threshold of committing to a project is not practical, because it could negate the need for a utility to make a section 10 filing altogether—if a project is being built and the utility has committed to pay costs, HB 2021 targets would be met and there is no reason for the utility to seek relief under section 10.

The draft order further states, “If a utility believes that a cost or investment qualifies for the cost cap, we encourage it to make a section 10 filing promptly.” And “we reiterate that the utilities can and should submit section 10 filings when they have the information available to do so . . .”<sup>7</sup> If it is too early to make a section 10 filing concurrent with an IRP/CEP, if it is too late to make a section 10 filing concurrent with a rate proceeding, and there is no need to seek relief under section 10 if a utility has already committed to a project, then it seems most practical to consider HB 2021 cost cap implications when a utility is faced with a *decision* to move forward

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<sup>6</sup> *Id.* at 11.

<sup>7</sup> *Id.* at 10.

with a project that is needed to, in whole or in part, meet the emissions-reduction targets set forth in HB 2021. In the context of regulatory proceedings at the Commission, the point in time that is closest to when a utility’s decision to commit to a project is when a utility is seeking acknowledgement of an RFP shortlist.

Yet the draft order explains that “the timing of the RFP process does not allow for a parallel section 10 proceeding.”<sup>8</sup> PacifiCorp requests the Commission reconsider this statement, and encourage utilities to seek an expedited section 10 proceeding when seeking acknowledgement of an RFP final shortlist if the utility’s final shortlist is informed by an HB 2021 cost cap assessment. Importantly, information available to the utility when evaluating bids from an RFP, while imperfect, is substantially improved relative to the information available when preparing an IRP/CEP. For instance, RFP data include cost-and-performance attributes for real projects with firm bids resulting from a Commission-approved competitive solicitation that is implemented with the oversight of an independent evaluator as opposed to proxy resource assumptions included in an IRP/CEP preferred portfolio.

For PacifiCorp specifically, and with HB 2021’s fast-approaching 2030 compliance deadline, it is important that the Commission issue a cost cap determination before utilities enter into contracts. It is also important that the Commission complete its cost cap investigation quickly. For projects that the utility is proposing to move forward, commercial agreements could include conditions that make a contract’s effectiveness contingent on a section 10 cost cap decision; however, these provisions do not come without cost. The risk is heightened by a possible 8–10-month timeline that is often used for many contested cases. For projects where the utility is proposing not to move forward with a project, it is highly unlikely that a project developer (or construction contractor, in the case of an owned asset) would agree to proceed with negotiating a commercial contract that the utility is proposing *not* move forward conditioned on the outcome of a section 10 cost cap decision. For this circumstance, contract negotiations would likely not begin until a section cost cap decision is made, and then, only if that decision concludes the project does not push the cost cap above 6 percent. Delays in resolving cost cap proceedings would introduce significant uncertainty and added cost into the contracting process.

To mitigate this risk, PacifiCorp recommends the Commission establish a fast-track cost cap proceeding that can be resolved within 90–120 days. ORS 469A.445(2)(a) does not preclude such an expedited process, as it does not specify minimum durations or procedural timelines that would prevent one.

### **C. Interaction between HB 2021 and Renewable Portfolio Standard Cost Caps**

PacifiCorp finds that language in the draft order appropriately and accurately recognizes that a resource acquired for HB 2021 compliance will also often lead to the procurement of renewable energy certificates (RECs) that contribute to a utility’s compliance with Oregon’s renewable portfolio standard (RPS). The draft order also outlines a circumstance where an RPS-

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<sup>8</sup> *Id.* at 10.

eligible resource that is more costly than an alternative non-emitting resource (presumably without RECs) in order to meet the bundled REC requirement of the RPS and concludes that the incremental cost of this procurement would be attributed to the RPS cap and not the HB 2021 cap.<sup>9</sup> This conclusion (i.e., excluding any cost from applying to HB 2021) seems contradictory to language in the draft order under section II.A, which finds that resource decisions often have co-benefits that the commission will use to apportion costs as applicable to the HB 2021 cost cap.<sup>10</sup> It is unclear why a portion of the cost for an RPS-eligible resource with RECs would not apply to HB 2021, considering HB 2021 compliance would be a co-benefit of this resource procurement. PacifiCorp requests additional clarification on this issue.

#### **D. The Period for Cost Cap Application**

PacifiCorp supports language in the draft order stating that the cost cap “does not permit an additional six percent rate increase every year,” and instead measures whether cumulative HB 2021 costs exceeds six percent of the utility’s revenue requirement for that year.<sup>11</sup> However, there are issues that remain to be settled around the implementation of details and are further discussed in Section IV, subpart c of these comments.

### **III. COUNTERFACTUAL PORTFOLIO**

This section details the company’s vision for developing a counterfactual portfolio, specifically addressing the role of replacement resources needed to satisfy ORS 757.518 (elimination of coal-fired resources from rates), the role of small-scale renewable (SSR) resources, and the role of transmission investments for cost cap purposes.

For context, PacifiCorp presented two counterfactuals in its 2025 CEP—one that eliminates HB 2021 emissions-reduction targets, and another that eliminates HB 2021 emissions-reduction targets and the SSR target. PacifiCorp did not develop a counterfactual portfolio to quantify the impacts of ORS 757.518; however in its 2025 CEP, the company noted that costs associated with requirements to eliminate coal from rates by 2030 may be appropriately accounted for in the HB 2021 cost cap.<sup>12</sup> The following comments are not structured to describe the counterfactuals produced in PacifiCorp’s 2025 CEP, which were produced before the draft order was issued. Rather, the following comments more broadly describe how a counterfactual might be developed in future CEPs, and in any future section 10 filing.

#### **A. Replacement Resources to Satisfy ORS 757.518**

Oregon law requires utilities remove coal-fired resources from customer rates by 2030.<sup>13</sup> Absent this requirement, PacifiCorp’s Oregon customers would be allocated costs from

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<sup>9</sup> *Id.* at 13.

<sup>10</sup> *Id.* at 5-6.

<sup>11</sup> *Id.* at 15.

<sup>12</sup> *PacifiCorp’s 2025 Clean Energy Plan* in Docket LC-85 at 72 (Jun. 30, 2025).

<sup>13</sup> ORS 757.518(1).

approximately 875 MW of coal resource capacity (nameplate). When accounting for capacity contribution values of potential non-emitting replacement resources based on the Western Resource Adequacy Program, removal of this coal capacity from the Oregon jurisdictional portfolio is a significant contributor to near-term resources in PacifiCorp's 2025 CEP preferred portfolio. By the end of 2030, this portfolio includes over 2,000 MW of utility-scale wind and solar resources and approximately 700 MW of battery-storage capacity.<sup>14</sup>

Because of HB 2021, PacifiCorp plans to procure only non-emitting resources or storage that reduce dispatch from emitting resources and unspecified market purchases, to replace the need previously met by coal resources. If it were not for HB 2021, PacifiCorp could consider all resource types, except for coal, when procuring new resources to replace the coal capacity that must be removed from rates by 2030. Consequently, PacifiCorp envisions that its counterfactual would eliminate HB 2021 emissions-reduction targets *and* all appropriate restrictions on the types of resources that can be used to replace coal resources that must be removed from rates by 2030 (i.e., allowing all types, including new natural gas-fired resources and unspecified market purchases, while eliminating all uses of coal, including carbon capture). This is particularly important when considering the limited availability and outright elimination of federal tax credits for certain non-emitting resources. This approach is consistent with language in Section II.A of the draft order finding that when determining a cost or investment contributes to compliance, the Commission must also determine what costs or investments are being displaced and include only the difference in the cost cap calculation.<sup>15</sup>

## **B. Incremental SSR Resources**

PacifiCorp agrees with the Commission that the majority of costs to procure SSR resources are excluded from HB 2021's cost cap.<sup>16</sup> However, PacifiCorp envisions including incremental SSR resources needed to satisfy the SSR obligation *caused* by the increase in nameplate generation capacity resulting from procurement of HB 2021-driven resources. Costs for any incremental SSR obligation are relevant to the HB 2021 cost cap, because they are caused directly by actions that need to be taken to satisfy requirements set forth in sections 1 through 15 of HB 2021. This becomes applicable if total nameplate capacity of resources in the preferred portfolio (HB 2021 compliant) exceeds the nameplate capacity in a counterfactual that removes constraints that limit the types of new resources (except for coal) that can be used to meet the needs of Oregon customers. This approach is also consistent with language in Section II.A of the draft order finding that when determining a cost or investment contributes to compliance, the Commission must also determine what costs or investments are being displaced and include only the difference in the cost cap calculation.<sup>17</sup>

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<sup>14</sup> *In re PacifiCorp's 2025 CEP*, at 8.

<sup>15</sup> *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Notice and Memorandum, at 7 (May 27, 2025).

<sup>16</sup> Draft Order, at 1, FN 1 ("This excludes any costs associated with compliance with the statute's remaining twenty-five sections; for example, energy purchases from small-scale renewable energy projects required by ORS 469A.210 do not count toward the cost cap.").

<sup>17</sup> *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Notice and Memorandum, at 7 (May 27, 2025).

## C. Transmission Investments

PacifiCorp envisions including transmission costs and investments (i.e., network upgrades associated with new resource interconnections, network upgrades associated with designated network resource requests for transmission service, and third-party firm transmission rights, as applicable), net of revenue credits, from third-party transmission customers, in its counterfactual. This approach will identify how transmission costs change between the IRP/CEP preferred portfolio and a portfolio without HB 2021, so that the net change in costs can be included in the HB 2021 cost cap. Changes can reflect a difference in timing of transmission investments, the addition of transmission investments, and the removal of transmission investments. This approach is also consistent with language in Section II.A of the draft order finding that when determining a cost or investment contributes to compliance, the Commission must also determine what costs or investments are being displaced and include only the difference in the cost cap calculation.<sup>18</sup>

Under the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol), transmission costs are dynamically allocated among all of PacifiCorp's states' customers. PacifiCorp has proposed to maintain this approach in its recently filed application seeking approval of the 2026 PacifiCorp Inter-Jurisdictional Allocation Protocol (2026 Protocol).<sup>19</sup> However, the proposed 2026 Protocol outlines a phased approach to transition the allocation of costs to align with changes in operations and to establish rate base in a manner that aligns costs and benefits consistent with state energy policies. In the proposed 2026 Protocol, PacifiCorp states that it will present a second phase filing to be effective no later than 2030 that will address a broader scope, including a review of how transmission costs will be allocated.<sup>20</sup> Oregon's allocated share of the cost for transmission needed for HB 2021 compliance will be based on the cost-allocation methodology approved by the commission at the time an IRP/CEP or a request for a section 10 investigation is filed.

## IV. HYPOTHETICAL EXAMPLE

### A. Application to the Draft Order

The background and assumptions for the hypothetical scenario indicate that the Commission determined, before 2030, that a utility had committed to projects that contribute to HB 2021 compliance and that the costs did not meet the 6 percent cost cap threshold for 2030 and 2031. Consistent with PacifiCorp's comments on section II.B of the draft order, it is not clear why the utility would need to seek an exemption once it had committed to the projects, which would presumably authorize the projects to move forward. Similarly, in the hypothetical example, it is not clear why the utility would need to seek a section 10 exemption in 2030 for contracts executed from the 2030 RFP for the years 2033 through 2035 since those projects are committed

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<sup>18</sup> *In re Commission HB 2021 Investigation*, Docket No. UM 2273, Notice and Memorandum, at 7 (May 27, 2025).

<sup>19</sup> *In the Matter of PacifiCorp, d/b/a Pacific Power, Application for Approval of 2026 Inter-Jurisdictional Allocation Protocol*, Docket No. UM 240, PAC201, Link/4-5 (Aug. 1, 2025).

<sup>20</sup> *Id.* at PAC/200, Link/5.

and moving forward, thereby contributing to the HB 2021 emission-reduction targets as planned, regardless of cost.

PacifiCorp's concerns with having a utility commit to a resource before making a section 10 is amplified as the hypothetical scenario moves into actions taken in 2031. In 2031, the commission finds that the cumulative impact on rates exceeds 6 percent in 2034 and 2035 and grants an exemption. The practical outcome of this scenario, because the utility had already committed to the projects, is that cumulatively, rates are likely to exceed the 6 percent cost cap in 2034 and 2035, and the utility is still likely to hit compliance (because the projects will come online and reduce emissions). At the same time, the utility was granted an exemption from the HB 2021 emission-reduction targets that it does not need, allowing it to alter its actions by delaying retirement of a gas plant by one year (from 2035 to 2036), which will actually put upward pressure on emissions. Pegging a section 10 filing to committed projects, as shown in the hypothetical example, can render the cost cap meaningless (i.e., costs are still going up by more than 6 percent in 2034 and 2035, at least on a forecast basis) while also enabling increased emissions.

## **B. When Will Utilities Have Information to Support an Action?**

PacifiCorp uses available information at the time it is making a decision to commit to an action (i.e., committing to procure a resource via a contract, such as a power-purchase agreement or a build-transfer agreement). However, information is available to a utility leading up to the decision point where the utility formally commits to an action. As addressed in PacifiCorp's comments on section II.B. of the draft order, information is available at the time a utility establishes a final shortlist toward the end of the RFP process. For PacifiCorp, this information includes firm pricing and resource performance characteristics validated by a third-party. The information also includes comprehensive economic analysis of final shortlist bids (and going forward, will include an assessment of HB 2021 compliance implications), used to support selection of that final shortlist using a Commission-approved scoring and selection process implemented with the oversight of an independent evaluator.

PacifiCorp recognizes that this information can change between the time a final shortlist is proposed and the time that a decision is made to commit to a resource action; however, in most instances, when changes occur, it is not common that they cause a change in the ultimate decision to proceed with a project. The Commission must weigh the pros and cons of opening an investigation in response to a section 10 filing at different points in time, recognizing that uncertainties will be an issue no matter when an investigation in response to a section 10 filing is made (i.e., the forecast of revenue requirements alone will be uncertain regardless of what is known or not known about the information supporting a resource action). With consideration of these pros and cons, PacifiCorp maintains that it is better to consider a section 10 filing, on an expedited basis, at the time a final shortlist is established than to wait until a utility is committed to a resource decision. As discussed above in section IV.A. of these comments, waiting until a utility commitment can actually negate the need for a section 10 filing altogether and potentially, and unnecessarily, lead to increased emissions.

**C. How Will Utilities Develop Credible Estimates of Future Annual Revenue Requirements?**

Forecasting revenue requirement with any level of precision is difficult and that forecast's accuracy may not be significantly impactful, since the total level of revenue requirement is in the denominator for the cost cap calculation. PacifiCorp recommends that forecast revenue requirements be based upon the current authorized revenue requirement with adjustments made for the load forecast and known and measurable changes. This approach is defensible and transparent for stakeholders.

PacifiCorp recommends that the starting point for any estimate of future annual revenue requirements should begin with the methodology outlined in OAR 860-083-0200. However, a methodology to modify this forecast into a longer forward-looking calculation of Annual Revenue Requirement (ARR) is necessary. Additionally, how HB 2021 investments are reflected in the denominator for the ARR presents the difficulty of maintaining a counterfactual indefinitely to measure cumulative rate impacts of HB 2021 actions over time. Finally, the use of net present value revenue requirement (NPVRR) is not suited for a section 10 filing because it does not capture the depreciating rate base that is associated with an owned asset. As a result, PacifiCorp recommends that the utilities collaborate to develop a methodology to forecast ARR.

**D. What Events Are Likely to Warrant Updates to Years for Which an Exemption Is Not Granted?**

Any combination of events that cause actual and forecasted costs associated with sections 1-15 of HB 2021 could warrant updates to years for which a section 10 exemption was not granted. Assuming these events are the result of actions taken “for the purpose of” or of actions “that contribute to” compliance, some examples include, but are not limited to:

Changes to the numerator:

- Actual costs for an action are higher than anticipated (i.e., tariffs are imposed on materials needed to construct a generating resource or a transmission asset during the construction process, or a cultural find during excavation of a construction project causes mitigation plans that increase costs).
- A project is accelerated by a year to take advantage of overall “life-time” net cost savings (i.e., federal tax-credit law changes during the construction of a new renewable resource that would cause the taxpayer to lose eligibility for tax credits under the original timeline).

Changes to the denominator:

- Actual net power costs increase or decrease as market prices change, fuel costs change, and other inputs vary due to a myriad of factors, impacting overall ARR.

- Passage of new legislation in Oregon and/or the anticipated move towards multi-year rate plans with utilities having specific defined schedules for general rate cases causing larger variability in revenue requirement as depreciation may outpace capital expenditures in specific individual years.
- Changes in federal tax law that significantly impacts the company's ARR in unforeseen ways.
- Changes in PacifiCorp's inter-jurisdictional allocation methodologies that impact the ARR in unforeseen ways.

## V. CONCLUSION

PacifiCorp continues to appreciate the Commission's diligent efforts with HB 2021-related issues, and respectfully request the Commission consider the issues discussed above.

Respectfully submitted August 12, 2025,

/s/ Rick Link

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